ENERGY REPORT:
Industry Facts and Updates

to the
Regulatory Flexibility Committee

of the
Indiana General Assembly

by the
Indiana Utility Regulatory Commission

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Chairman William D. McCarty
Commissioner G. Richard Klein
Commissioner David Ziegner
Commissioner Camie Swanson-Hull

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I. PURPOSE AND SCOPE OF THE REPORT

This report is intended to satisfy the requirements of I.C. 8-1-2.5-9(b). The report outlines the status of competition in the Indiana energy utility industries, both electric and gas. The report reviews the activities of the energy industry in Indiana and provides an update of facts and developments since the Indiana Utility Regulatory Commission's 1997 Energy Report.[1] It also examines competition initiatives at the state and federal levels.

II. EXECUTIVE SUMMARY

The type of electric utility that is most significant in terms of generation and customers served is the investor-owned (IOU). Five major investor-owned utilities operate within the state: Indianapolis Power & Light (IPL), Indiana Michigan Power (I&M), Northern Indiana Public Service (NIPSCO), PSI Energy (PSI) and Southern Indiana Gas & Electric (SIGECO). Most IOUs are vertically integrated, meaning they own facilities for generation, transmission and distribution (T&D). IOUs are typically able to generate enough power for their own requirements and produce power for sale in the wholesale market.

There are 78 municipally owned electric utilities in Indiana, 31 of which are regulated by the Indiana Utility Regulatory Commission (IURC or the Commission). Municipal utilities typically own very little, if any, generating capacity; they purchase electricity from other sources and resell it to their retail customers. Many municipals in the state are members of the Indiana Municipal Power Agency (IMPA). IMPA was created by a group of municipalities in 1980 to jointly finance and operate generation and transmission facilities and purchase power.

Forty-three nonprofit electric distribution cooperatives exist in Indiana, 26 of which have opted out of Commission jurisdiction. They generally purchase electricity at wholesale rather than owning generation facilities. Within Indiana, there are two generation and transmission (G&T) cooperatives: Hoosier Energy and Wabash Valley Power Association. These G&T cooperatives serve as coordinators of bulk power supplies and transmission services for their members.

Data from the Energy Information Administration (EIA) for 1997 show that Indiana ranks as one of the lowest cost states for electricity. The less expensive western states have the advantage of hydropower and abundant coal reserves, as does Kentucky, while Tennessee has the Tennessee Valley Authority (TVA) to provide low-cost electricity. Indiana's favorable ranking

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[1] Energy Report, Indiana Utility Regulatory Commission, October 1997.

results from significant coal reserves and relatively little utility investment in expensive nuclear power.

In Indiana, there are three large investor-owned gas utilities, Indiana Gas, NIPSCO and SIGECO, and 17 smaller IOUs. The three largest IOUs are owned by holding companies, and two of them, NIPSCO and SIGECO, also operate major electric utilities. Gas IOUs, unlike their electric IOU counterparts, are not vertically integrated; they typically do not own gas production or pipeline facilities beyond their local distribution area.

There are 19 municipally owned gas utilities in Indiana, four of which are regulated by the IURC. The largest municipal gas utility is Indianapolis-based Citizens Gas and Coke. Like their IOU counterparts, municipal gas utilities serve as a "reseller" to the retail customers. Typically, municipal gas utilities purchase gas supply and transportation rights rather than having ownership in production or interstate pipeline facilities.

According to the EIA, the average natural gas price to Indiana residential and commercial customers is below the national average.

Movement toward deregulation of the gas industry has been synonymous with further unbundling of gas services, at both the wholesale and retail levels. The degree of unbundling can be used as a rough measure of deregulation by Indiana's gas utilities. NIPSCO has had the highest percentage of unbundled service over the past ten years, averaging 56 percent. It is followed by SIGECO, Indiana Gas and Citizens, with 41, 24 and 17 percent, respectively. The use of unbundled services by industrial customers has been more extensive than that of commercial customers. Marketers began transporting gas in April 1998 for residential customers under the "NIPSCO Choice" program.

Utility Activities

Update from the 1997 Energy Report

In June 1998, Indiana Statewide amended its June 1996 alternative regulatory plan (ARP) petition on behalf of 16 distribution REMCs.[2] The ARP in this petition is essentially the same as the one filed in 1996. A hearing has been set for September 1998 with an order expected sometime in October 1998. A second ARP petition filed by Indiana Statewide on July 21, 1997, has been dismissed.

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[2] Since the June 1996 filing, 16 of the original 32 REMCs have opted out of IURC jurisdiction.

On March 18, 1998, the IURC approved Indianapolis Power & Light's alternative regulatory plan for residential and small commercial customers. IPL must file a report with the Commission and the other parties involved in the case on the status of the ARP in 1999.

On September 12, 1997, the IURC denied a complaint filed against Citizens Gas and Coke Utility and Indiana Gas Co. by a group of their large industrial customers over the utilities' joint venture that formed ProLiance, an Indianapolis-based marketer of energy and related services that was formed in March 1996. The order was appealed by the OUCC, the CAC and the industrial customers. Briefs have been filed by all parties and the case was transmitted to the Court for decision on June 22, 1998.

On October 8, 1997, the Commission approved an alternative regulatory plan proposed by NIPSCO. The biggest challenge to date has been the implementation of the residential consumer choice program. Service began in April 1998 to customers that signed up for the NIPSCO Choice program. In June 1998, NIPSCO increased the number of eligible residential program participants from 55,000 to approximately 82,000. This number will increase to 150,000 eligible customers in year two of the program.

Activities since the 1997 Energy Report

The changing electric and gas utility industries continue to give rise to new mergers and acquisitions among utilities. "Convergence" mergers and acquisitions involve companies in previously unrelated markets that combine to achieve "economies of scope" so that services in both markets can be provided more economically than either firm could provide on a stand-alone basis. Electric utility diversification into telecommunications, for instance, has become increasingly common.

Both AEP and NIPSCO are involved in merger actions at this time. On December 22, 1997, American Electric Power (AEP) and Central and South West Corporation (CSW) announced a stock-for-stock merger transaction creating a company with a total market capitalization of approximately $28.1 billion. The IURC has intervened in the FERC dockets related to this merger.[3] Further, on June 29, 1998, the IURC announced an investigation into the merger between AEP and CSW (Cause No. 41210). The IURC believes that the proposed merger could have a significant impact on the electric industry and customers, both in Indiana and across the region. The IURC is also concerned about the proposed merger's effect on reliability of service and the development of independent system operators.

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[3] Docket Nos. ER98-2786-000, EC98-40-000, ER98-2770-000.

On March 20, 1998, NIPSCO Industries petitioned the Massachusetts Department of Telecommunications and Energy (DTE) to merge Bay State Gas Company (Bay State) with NIPSCO Industries. Two merger options were proposed. The Preferred Merger Structure would reorganize Bay State as a wholly owned subsidiary of NIPSCO Industries, with each company continuing to operate as separate corporations with their own books, records, capital structures, management structure and boards of directors. The Alternative Merger Structure would directly merge Bay State into NIPSCO Industries' primary gas subsidiary, Northern Indiana Public Service Company, which would operate Bay State as its Massachusetts division. All hearings at the DTE have concluded. The SEC is not expected to act on the merger until the Massachusetts Commission issues its ruling.

On March 25, 1998, the Commission opened Cause Number 41094, *"In the matter of the joint application for approval of certain transactions between Indiana Michigan Power Company and AEP Communications, LLC."* AEP Communications (AEPC), like Indiana Michigan Power Company, is a wholly owned subsidiary of American Electric Power. In addition to offering services to AEP's electric utility subsidiaries, AEPC intends to offer high-capacity private line and access services by providing fiber optic capacity. AEPC also intends to market land for the construction and operation of towers for personal communication services.

On May 15, 1998, Southern Indiana Gas & Electric Company's affiliate SIGECOM, another subsidiary of SIGCORP, filed a petition *"For a certificate of territorial authority to provide switched and special local exchange telecommunication services throughout the state of Indiana,"* designated as Cause Number 41172. SIGECOM was formed to undertake telecommunications operations with UTILICOM, an unaffiliated firm. Both petitions, Cause Numbers 41094 and 41172, are still pending before the Commission.

During the week of June 22, 1998, electric utilities in Indiana and throughout the Midwest struggled with record peak demands, capacity shortages and unprecedented wholesale price volatility. The IURC held fact-finding meetings on July 22 and 23, where Indiana's eight Generation and Transmission utilities presented briefings on the events of the week of June 22. Based on preliminary information, it appears that an unusual amount of unscheduled outages at generation plants, in combination with scheduled outages and unusually hot weather for June, that produced record peak demands for many utilities, led to problems of short supply and high wholesale prices.

Impacts varied among the customers of Indiana's electric utilities. Some utilities reported little effect on their customers either in terms of price or supply disruptions. Other utilities reported significant effects in that industrial customers with interruptible provisions in their contracts had service curtailed during the critical period. It is estimated that the adverse consequences for customers will be mitigated as the high prices were only in effect for a short period of time.

The IURC is planning to follow up with specific data requests of the utilities in order to get more detailed information. Additionally, the IURC has intervened at the FERC (Docket No. EL 98-53-000). Several utilities have also requested an investigation concerning the events of June 22.

On January 15, 1998, the Midwest Independent System Operator (MISO) filed for FERC approval, with nine transmission owners joining the proposed organization.[4] The IURC intervened in the case.[5] An announcement on December 9, 1997, of an intent to study the formation of a rival transmission entity by six Ohio and Michigan utilities[6] caused widespread defections among participants in the MISO. Since the FERC filing Central Illinois Light Company, Allegheny Energy and Duquesne Light Company (in process of merging) and Alliant Utilities have joined MISO.

Current MISO participants contend that the ISO is of sufficient size to form a viable and effective ISO but believe AEP's participation is essential if the full benefits of a large ISO are to be achieved. AEP continues discussions with both MISO and the Alliance group in the hopes of bringing the two groups together to form a broad regional ISO.

Restructuring at State and Federal Levels

Electric utility restructuring continues to be an active issue in most states since the 1997 Energy Report. In California, Rhode Island and Montana, some retail customers now have access to alternative electricity suppliers as a result of restructuring programs. Further, utilities in Idaho, Iowa, Washington and Oregon have initiated pilot programs that allow select groups of customers access to alternative electricity suppliers, although industry-wide restructuring is still under debate.

During the 1998 legislative session, three states passed extensive restructuring bills, Illinois, Connecticut and Virginia. A number of other states considered restructuring legislation that was

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[4] Signatories were Cinergy, Hoosier Energy, WVPA, Commonwealth Edison, Wisconsin Electric Power, Ameren, Kentucky Utilities, Illinois Power and Louisville Gas & Electric.

[5]Docket Nos. EC98-24-000 and ER98-1438-000.

[6] FirstEnergy, Detroit Edison, Consumers Power Company and Duquesne Light Company, Allegheny Power System, Inc. and Virginia Electric Power Company. The group is known as the Alliance transmission system entity.

either defeated or left pending at the end of the legislative session. Most other states are still in the process of addressing the electric utility restructuring issue.

Until 1996, customer choice options in the natural gas industry were largely limited to industrial, electric utility and large commercial customers. Since 1996, customer choice options have become increasingly available to residential customers as the gas industry continues its evolution to a deregulated market. Currently, twenty-one states and the District of Columbia have gas residential pilots that are underway or proposed. These programs will permit 31 percent of United States households to purchase their gas from a non-utility supplier. Combining this percentage with that for industrial and commercial customers, it is possible that more than 70 percent of gas consumed today could be purchased from non-utility sources.

The major development in federal restructuring legislation in 1998 was the release of the Clinton administration's Comprehensive Electricity Competition Plan which was presented to Congress in late June. The primary goal of the bill is to promote competition when it will benefit consumers. The bill's other objectives are to improve the environment through market forces: promote renewable energy and establish nitrogen oxide caps; strengthen service reliability; and assist and protect consumers through a public benefits fund and required information disclosure by suppliers.

Reliability continues to be a key issue in the electric utility restructuring debate. The Department of Energy's Electric System Reliability Task Force issued a position paper in November 1997, an interim report in March 1998 and two more technical reports in May 1998. It is expected to issue its final report in the fall of 1998. The main conclusion of the Task Force's March report was that independent system operators should cover as large an area as possible and should be implementers rather than creators of reliability standards.

The North American Electric Reliability Council (NERC), a voluntary industry group that oversees reliability concerns at the present time, has also been studying the issue. Based on a report issued in December 1997 by a blue-ribbon panel chosen to study the issue, the NERC Board of Trustees has approved a series of recommendations that will reform NERC into the North American Electric Reliability Organization. The transition will begin in January 1999.

III. INDIANA'S ENERGY MARKETS

A. Review of The Electricity Industry

1. Industry Structure

Electric utilities in the United States are categorized by their type of ownership--government (federal and municipal), cooperative and investor-owned. The utilities have the same goal, which is to provide reliable electric service at reasonable cost to their customers, but distinct corporate structures result in different methods employed by the utilities to meet this goal. Because of the differences in utility structure, government policy does not affect each type of utility in the same manner.

a. Investor-Owned Utilities (IOU)

The type of utility that is most significant in terms of generation and customers served is the investor-owned (IOU). Five major investor-owned utilities operate within the state: Indianapolis Power & Light (IPL), Indiana Michigan Power (I&M), Northern Indiana Public Service (NIPSCO), PSI Energy (PSI), and Southern Indiana Gas & Electric (SIGECO). IOUs are for-profit enterprises funded by debt and equity. IOUs are judged by the same standards as any publicly held company; investor services rate their bond issues and make recommendations on stock purchases. Most IOUs are vertically integrated, meaning they own facilities for generation, transmission and distribution. The significant level of investment needed to construct and maintain the systems results in high leverage for many IOUs.

All of Indiana's IOUs are owned by holding companies. Holding companies are entities that own enough stock in another company to influence management of the held company. Holding companies are popular in the electricity industry because its capital-intensive nature makes it economical to combine functions. Two of the state's IOUs, PSI Energy and Indiana Michigan Power, are subsidiaries of multi-state holding companies (Cinergy and American Electric Power, respectively). Multi-state holding companies are required under the Public Utility Holding Company Act (PUHCA) to register with the Securities and Exchange Commission (SEC), and the SEC monitors their actions to ensure compliance with PUHCA regulations.

Table 1 presents generation and sales information for Indiana's five major IOUs. The "Sales for Resale" illustrates that IOUs are typically able to generate enough power for their own requirements and produce power for sale in the wholesale market.

Table 1: Investor-Owned Utility Statistics -- 1997

UTILITY	CAPACITY (MW)	TOTAL SALES (GWh)	SALES FOR RESALE (GWh)	RESIDENTIAL SALES (GWh)	COMMERCIAL SALES (GWh)	INDUSTRIAL SALES (GWh)
I&M	4,443	34,546	17,500	5,075	4,349	7,540
IPL	2,968	14,258	1,140	4,255	1,960	6,834
PSI	5,968	56,617	33,317	7,055	5,960	10,220
NIPSCO	3,392	15,992	1,179	2,724	2,975	8,971
SIGECO	1,236	6,285	1,753	1,251	1,192	2,067

Source: 1997 Annual Reports to the IURC and IURC Annual Reports 1996-97

b. Municipal Utilities

There are 78 municipally owned electric utilities in Indiana, 31 of which are regulated by the IURC. Municipals are organized as nonprofit local government agencies and pay no taxes or dividends, although net revenue can be turned over to the general city fund if the city elects to do so. Municipals raise capital through the issuance of tax-free bonds.

Municipal utilities typically own very little, if any, generating capacity; they purchase electricity from other sources and resell it to their retail customers. The reseller status limits a municipal's need to raise large amounts of capital because it does not invest in capital-intensive generation. The advantages of a "muni" include the local government receiving revenue from earnings, and generally lower electricity rates for the municipality due to the low capital investment and tax-exempt status.

Many municipals in the state are members of the Indiana Municipal Power Agency (IMPA). IMPA was created by a group of municipalities in 1980 to jointly finance and operate generation and transmission facilities and purchase power. IMPA is a political subdivision of the state under Indiana Code 8-1-2.2 and is not subject to state or federal income taxes.

IMPA owns generating facilities and has member-dedicated generation. It also holds ownership interest in two units, Gibson 5 (co-owned with PSI and Wabash Valley Power Association) and Trimble County 1 (co-owned with Louisville Gas and Electric and the Illinois Municipal Electric Agency). It meets the rest of its members' needs through purchased power.

c. Cooperatives

Another type of nonprofit electric utility is the cooperative. Forty-three distribution co-ops exist in Indiana, of which 26 have opted out of Commission jurisdiction. Co-ops were originally formed to bring electric service to rural areas. They are similar to municipals in that they generally purchase electricity at wholesale rather than owning generation facilities.

Although co-ops were created to distribute power, since the 1960s over 50 generating and transmission (G & T) cooperatives have been formed nationally to supply power to distribution co-ops. Within Indiana, there are two G & T co-ops: Hoosier Energy and Wabash Valley Power Association. These G & T co-ops serve as coordinators of bulk power supplies and transmission services for its members, as IMPA does for municipals.

Table 2 illustrates the proportion of power purchases to generation for IMPA and the generation and transmission cooperatives, Hoosier Energy and Wabash Valley Power Association. The table illustrates that Hoosier Energy owns a significant amount of generating capacity compared to Wabash Valley.

Table 2: IMPA/G&T Cooperative Statistics -- 1997

UTILITY	CAPACITY (MW)	GENERATION (GWh)	PURCHASES (GWh)	SALES (GWh)
IMPA	555	1,688	3,108	4,585
Hoosier Energy	1,266	8,975	868	9,110
Wabash Valley	156	1,161	4,243	5,206

Source: 1997 Annual Reports to the IURC, Company Annual Reports, and communication with the companies.
"Losses" account for the difference between the sum of generation + purchases and sales

2. Indiana Electricity Prices

Table 3 presents a comparison of average electric utility revenue per kWh by state for 1996. It is important to note Indiana's position near the bottom of the revenue per kWh rankings, indicating Indiana is a low-cost state. The cheaper western states have the advantage of hydropower and abundant coal reserves, as does Kentucky, while Tennessee has the TVA to provide low-cost power. Indiana's favorable ranking comes not only from its coal reserves, but also from relatively little utility investment in expensive nuclear power.

For more detailed revenue, sales and market share information for Indiana utilities, please see Appendix 1.

Table 3: Average Revenue, Cents Per kWh by Sector and State -- 1996

State	Residential	Commercial	Industrial	Other	All Sectors (rank: highest to lowest)
Hawaii	14.2	12.9	10.0	12.8	12.1
New Hampshire	13.6	11.4	9.2	15.6	11.7
New York	14.1	12.1	5.3	9.1	11.2
Connecticut	12.1	10.3	7.9	13.9	10.5
Rhode Island	11.9	10.2	8.6	11.8	10.5
New Jersey	12.0	10.4	8.2	18.3	10.5
Massachusetts	11.3	10.0	8.6	14.4	10.2
Alaska	11.2	9.5	8.3	16.5	10.2
Vermont	11.1	10.2	7.6	17.0	9.8
Maine	12.6	10.4	6.4	23.8	9.6
California	11.3	9.7	7.0	4.8	9.3
Pennsylvania	9.7	8.3	5.9	11.2	7.9
Illinois	10.4	8.0	5.3	6.8	7.8
Arizona	8.9	7.9	5.3	5.1	7.6
District of Columbia	7.8	7.4	4.4	6.4	7.3
Florida	8.1	6.8	5.2	7.0	7.3
Michigan	8.5	8.0	5.2	11.0	7.2
Maryland	8.3	6.9	4.2	9.2	7.0
Delaware	8.9	7.0	4.7	11.9	6.9
US Average	**8.4**	**7.6**	**4.6**	**6.7**	**6.9**
New Mexico	8.9	7.9	4.3	6.1	6.8
Kansas	7.8	6.7	4.7	12.2	6.5
Georgia	7.7	7.2	4.3	8.4	6.5
North Carolina	8.0	6.4	4.8	6.7	6.5
Ohio	8.6	7.7	4.2	6.3	6.3
South Dakota	7.1	6.7	4.5	4.7	6.3
Arkansas	7.8	6.8	4.5	6.7	6.2
Missouri	7.1	6.1	4.5	7.2	6.1
Virginia	7.6	5.9	4.0	5.2	6.1
Louisiana	7.7	7.1	7.1	4.3	6.1
Texas	7.6	6.6	4.0	6.3	6.1
Colorado	7.6	5.9	4.5	7.5	6.1
Mississippi	7.1	7.1	4.3	8.5	6.0
Iowa	8.2	6.6	3.9	6.0	5.9
Nevada	6.9	6.6	4.8	4.5	5.9
South Carolina	7.5	6.4	3.9	6.0	5.7
Minnesota	7.3	6.2	4.3	7.2	5.6
North Dakota	6.1	6.1	4.5	3.8	5.6
Oklahoma	6.7	5.7	3.7	5.0	5.5
Indiana	**6.9**	**6.0**	**3.9**	**9.2**	**5.3**
Wisconsin	6.9	5.7	3.7	7.0	5.3
Alabama	6.6	6.4	3.8	5.8	5.3
Utah	6.9	5.9	3.6	4.6	5.3
Nebraska	6.3	5.4	3.7	5.4	5.2
West Virginia	6.4	5.7	3.9	8.9	5.2
Tennessee	5.9	6.1	4.3	7.4	5.2
Montana	6.3	5.6	3.6	6.4	5.0
Oregon	5.8	5.2	3.4	5.8	4.8
Wyoming	6.1	5.1	3.4	4.2	4.3
Washington	5.1	4.9	2.9	3.7	4.2
Kentucky	5.7	5.2	2.9	4.6	4.1
Idaho	5.3	4.3	2.7	4.5	4.0

Source: U.S. Department of Energy, Energy Information Administration, Electric Power Annual 1996, August 1997, p.42.

B. Recent Developments in Electricity

1. Alternative Regulatory Plans

a. Indiana Statewide

Indiana Statewide Association of Rural Electric Cooperatives, on behalf of 32 Rural Electric Membership Cooperatives (REMCs), filed a petition with the IURC on June 10, 1996, seeking approval of an alternative regulatory plan (ARP). The proposed ARP was the first by an electric utility under IC 8-1-2.5.

Indiana Statewide petitioned the IURC to decline to exercise its jurisdiction over the petitioning REMCs on most issues, although the cooperatives would not formally opt out of IURC jurisdiction. Specifics of the plan included:

1. The ARP would give deference to the REMC's management with respect to personnel, operating and management practices affecting rates and charges.
2. The REMC's rates would be independent of the rates of its wholesale supplier.
3. Reductions in revenues applied to all rate classes using an existing rate design based on a cost-of-service study performed consistent with generally accepted practices and filed with the IURC would be presumed reasonable, and may be placed in effect upon thirty days' notice to members.
4. Reductions involving new rate design based on cost-of-service established by a current cost-of-service study filed with the IURC may be implemented thirty days after notice of the proposed rate changes to customers and shall become permanent within sixty days of such notice unless a petition for a hearing is requested within thirty days' of notice by the Office of the Utility Consumer Counselor (OUCC) or one percent of the REMC's members. The rates proposed by the REMC would be presumed reasonable and the person(s) filing the request for hearing would have the burden of proving otherwise.
5. Increases in recurring rates would be conclusively presumed reasonable and may be placed into effect upon thirty days' notice to members if the new rates do not produce additional annual revenues of more than three percent and the rate design is consistent with a cost-of-service study on file with the IURC.
6. Other rate increases would be placed into effect upon thirty days' notice to members and would become permanent sixty days thereafter unless a request for rehearing is received from the OUCC or one percent of the REMC's members within twenty days. The proposed rates once placed into effect would not be subject to refund.

7. The ARP provides for customer-specific contracts for new load or to retain existing load in excess of one megawatt, at the sole discretion of the REMC's board and without the necessity of IURC approval. The ARP would also require the IURC to keep the contract on file, but it would be on a confidential basis.

On August 8, 1996, the OUCC filed a Motion to Dismiss along with a Memorandum In Support of the Motion to Dismiss. This Motion was joined by Citizens Action Coalition (CAC), and Central Soya and General Motors. On September 5, 1996, the IURC denied the Motion to Dismiss. The CAC and OUCC initiated an interlocutory appeal, thus staying the proceedings until the Court of Appeals issued a ruling on the Motion to Dismiss. The Court of Appeals affirmed the IURC's decision to deny the motion to dismiss, thereby allowing the IURC to resume consideration of the case.

On July 21, 1997, Indiana Statewide filed a new petition, "1997 PETITION," under a new cause number, seeking IURC approval of an ARP that was somewhat different than the 1996 ARP. This petition was later dismissed.

In June 1998, Indiana Statewide filed an amended petition on behalf of 16 distribution REMCs.[7] The ARP in this petition is essentially the same as the one filed in 1996. A hearing has been set for September 1998, with an order expected sometime in October 1998.

b. Indianapolis Power & Light

On August 21, 1997, Indianapolis Power & Light Company filed an alternative ratemaking plan with the Indiana Utility Regulatory Commission. The plan would allow residential and small commercial customers with loads of less than 2,000 kW of demand the option of choosing one of three alternative pricing options.

Under the Sure Bill Option, available only to residential customers who have been at the same location for at least one year, the customer will pay the same charge each month for a year, regardless of how much electricity is used. There will be no bill reconciliation at the end of the year. The monthly charge will be based on the customer's electricity usage for the previous 12 months and the base rates, including fuel costs and the recovery of lost revenues from demand-side management programs, applicable to the customer at the start of the option. At the end of one year the customer may reapply for the Sure Bill option. At that time, the monthly charge would be updated to reflect the most recent usage levels and rates.

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[7] Since the June 1996 filing, 16 of the original 32 REMCs have opted out of IURC jurisdiction.

Under the Fixed Rate Option, the customer can choose to pay the same fixed rate for electricity for a period from one to three years. During the length of the contract, the fixed rate will not be affected by any changes in IPL's basic rates and charges.

The "Green Power" Option will allow customers to choose renewable resource power to displace some or all of their usual source of electricity. The portion of the customer's electricity supply being provided through renewable resources will be sold at a premium to IPL's usual rates and charges.

IPL plans to offer incentives to encourage participation in these options. The incentives could include credits to the customer's bill, energy saving products or services or contributions to the customer's preferred charity. IPL will limit the availability of these three options to 3 years 6 months, after which the options will be discontinued.

On January 30, 1998, an evidentiary hearing on the ARP was held. At that time IPL presented a Settlement Agreement executed by IPL, the Office of Utility Consumer Counselor and the Citizens Action Coalition agreeing to the terms of the ARP. Subsequently, the Commission approved the plan on March 18, 1998. Some operational problems delayed the start of the ARP until mid-July 1998.

It is unknown at this time what the consumer response has been to the ARP. As a provision of the Settlement Agreement, IPL must file with the Commission and the parties to the Agreement an annual report on the ARP. The first report is due in 1999.

2. Industry Convergence and Diversification

Electric and gas utilities have diversified into a wide range of activities, including acquisition of water utilities, financial institutions, home security, automobile auctions, home repair and real estate. Diversification can provide benefits to consumers and investors. There are, however, potential adverse consequences.[8]

"Convergence" mergers and acquisitions involve companies in previously unrelated markets that combine to achieve "economies of scope" so that services in both markets can be provided more economically than either firm could provide on a stand-alone basis. Electric utility

[8] In the last several years, diversification efforts by electric utilities into non-energy related businesses have had mixed success. Pinnacle West's (the parent of Arizona Public Service Company) ownership of a savings & loan that ultimately filed for bankruptcy is a notable example of a disastrous diversification program that resulted in rate increases for the customers of Arizona Public Service Company.

diversification into telecommunications, for instance, has become increasingly common.[9] If there are economies of scope, consumers could realize substantial benefits from more efficient and reliable electric operations as well as from increased competition in the telecommunications markets. The Public Utilities Holding Company Act (PUHCA) was amended by Section 103 of the Telecommunications Act of 1996 to allow electric utilities to form "exempt telecommunications companies" (ETCs).

From a regulatory perspective there are a number of issues regarding convergence mergers and acquisitions. First, there is a concern that captive customers of the regulated enterprise could be forced to subsidize the activities of the affiliated firm in the competitive market. Second, for regulated utilities that have "stranded costs," there is a concern that revenues could be diverted from buying down stranded costs to pay for mergers or acquisitions. Third, because of the additional risk associated with competitive markets, the financial health of the regulated utilities might be adversely affected. Fourth, regulated utilities have a wealth of customer information and will realize a substantial competitive advantage if that information is unavailable to its competitors.

The following is a list of the types of industry convergence that has been proposed or has occurred in Indiana. For the pending applications involving Southern Indiana Gas & Electric Company and American Electric Power Company, the capsulized information is contained in their petitions.

On May 15, 1998, Southern Indiana Gas & Electric Company's affiliate SIGECOM, another subsidiary of SIGCORP, filed a petition *"For a certificate of territorial authority to provide switched and special access local exchange telecommunications services throughout the state of Indiana,"* designated as Cause Number 41172. SIGECO has formed a separate subsidiary (SIGECOM) to undertake telecommunications operations with UTILICOM, an unaffiliated firm. A member of SIGECOM's Board of Directors testified:

> SIGECOM seeks authority to offer a full range of local exchange and switched access services through a combination of its own facilities and the resale of services of the incumbent local exchange carrier. . . In addition, SIGECOM intends to make available to subscribers a unique package of services, including voice, video, data, cable television, and

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[9] Electric utilities and, to a lesser extent, gas utilities own about 600,000 miles of high-capacity fiber optic cable. Much of this capacity is unused and leased to others. AT&T, for instance, currently leases over 30,000 miles of fiber optics cable from electric utilities. According to the Utility Telecommunications Association, electric utilities already account for 12% of all telecommunications networks in the United States. Source: Howard Caine in "*Electric Utilities and the Telecommunications Act of 1996: Should They or Shouldn't They, and When They Do, How Should Regulators React to the Issues*?" Presented to the Mid-Atlantic Conference of Regulatory Utilities Commissioners. Hot Springs, Virginia, July 2, 1997, p. 4.

Internet access. Initially, SIGECOM intends to provide service in Evansville, Newburgh and portions of Vanderburgh and Warwick counties.

On March 25, 1998, the Commission opened Cause Number 41094, *"In the matter of the joint application for approval of certain transactions between Indiana Michigan Power Company and AEP Communications, LLC."* AEP Communications (AEPC), like Indiana Michigan Power Company, is a wholly owned subsidiary of American Electric Power. In addition to offering services to AEP's electric utility subsidiaries, AEPC intends to offer high-capacity private line and access services by providing fiber optic capacity. AEPC also intends to market land for the construction and operation of towers (e.g., Personal Communications Services-PCS and other wireless providers).

In 1997, NIPSCO acquired Indianapolis Water Company (see page 14 of the 1997 Energy Report).

3. Noteworthy 30-Day Filings By Electric Utilities

Thirty-day filings are requests from utilities for approval of new rates, changes to non-recurring charges, altered rules and regulations or changes in periodic trackers. The 30-day filing process is designed to allow these types of requests to be reviewed and approved by the Commission in a more expeditious and less-costly manner than a formally docketed case. Last year, the Commission reviewed and approved more than 700 of these 30-day filings.

The IURC approved two significant 30-day filing proposals by Indiana Michigan Power Company. The first, approved by the IURC on June 24, 1998, was a proposal to have a Standard Contract Addendum for electric service as an option for customers served under Tariff Contract Service-Interruptible Power (C.S. - IRP.) Under the provisions of Tariff C.S.-IRP, large industrial customers enter into customer-specific contracts with I&M to have portions of their load subject to interruption in exchange for a lower price for electricity. The customers, at the time of an interruption, can either have their service interrupted or "buy through" the interruption if the utility is able to purchase and deliver power from another source. I&M anticipated that the number of times these customers might be interrupted during the summer of 1998 was going to be higher than normal and the price for buy-through power was also going to be higher than normal. The Standard Contract Addendum provided another option for these customers to choose to have I&M purchase a block of power at an agreed-upon, market-driven price for one or more time increments ahead of the time interruptions might be expected. These increments are the periods ending July 3, July 31, and August 28, 1998.

The second I&M proposal, approved by the IURC on July 8, 1998, created a service called Rider TEC (Temporary Emergency Curtailable Service). In essence, large customers who would otherwise not have their loads curtailed agree to curtailment in exchange for receiving a payment from I&M. Customers may submit bids to I&M specifying the price in cents per kWh at which they want service curtailed, the amount of electricity curtailed, and the number of hours during which the load may be curtailed. Rider TEC will expire on September 30, 1998.

The IURC approved two 30-day filings for Indianapolis Power and Light Company in regard to Tariff CSC (Customer Specific Contracts). Tariff CSC was approved by the IURC on August 24, 1995, as part of Cause No. 39938. The purpose of Tariff CSC is to provide an appropriate response to non-standard or specialized customer requests for electric services and/or adjust to competitive forces in the energy services markets in a manner that satisfies the needs of participating customers while balancing the interests of all customers and the company. Each Customer Specific Contract submitted by IPL is processed using the 30-day filing procedure and criteria contained in the tariff and the order. Most details of the contracts are confidential. The IURC approved a CSC between Wishard Hospital and IPL on October 29, 1997, and another CSC between Eli Lilly and IPL on July 15, 1998. Both customers had indicated they intended to install their own generating units and discontinue purchasing energy from IPL.

4. Electricity Capacity Shortage and Record Wholesale Prices During the Week of June 22, 1998

The week of June 22, 1998, was a serious operational week for electric utilities in Indiana and the Midwest region. The IURC held fact-finding meetings on July 22 and 23, where Indiana's eight Generation and Transmission utilities presented briefings on the events of the week of June 22.[10] Based upon preliminary information, it appears that an unusual amount of unscheduled outages at generation plants, in combination with scheduled outages and unusually hot weather for June, which created new record peak demands for many utilities, led to problems of short supply and high wholesale prices.

Impacts varied among the customers of Indiana's electric utilities. Some utilities reported little effect on their customers either in terms of price or supply disruptions. Other utilities reported significant effects in that industrial customers with interruptible contracts had service curtailed. It is estimated that the adverse consequences for customers will be small, however, as the high prices were in effect for such a short period of time.

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[10] The participants were IPL, Cinergy, NIPSCO, SIGECO, AEP-I&M, Hoosier Energy, IMPA and WVPA.

C. Review of the Natural Gas Industry

1. Industry Structure

Gas utilities in the United States are categorized into municipally owned and investor-owned. Despite their different forms of ownership and corporate structures, municipal and investor-owned utilities share the goal of providing reliable gas service at reasonable cost. Because of the differences in governance and corporate structure, government policy does not affect each type of utility in the same manner.

a. Investor-Owned Utilities (IOU)

Investor-owned utilities are the largest sellers of natural gas to retail customers in the United States. In Indiana, there are three large investor-owned gas utilities, Indiana Gas, NIPSCO and SIGECO, and 17 smaller IOUs. The three largest IOUs are owned by holding companies, and two of them, NIPSCO and SIGECO, also operate major electric utilities. Gas IOUs, unlike their electric IOU counterparts, are not vertically integrated; they typically do not own gas production or pipeline facilities beyond their local distribution area.

b. Municipally Owned Utilities

There are 19 municipally owned gas utilities in Indiana. The largest municipal gas utility is Indianapolis-based Citizens Gas and Coke. Of the 19 municipal gas utilities in Indiana, four are regulated by the IURC. Municipals are organized as not-for-profit local government agencies and pay no taxes or dividends, although net revenue can be turned over to the general city fund (in lieu of taxes) if the city elects to do so. Municipal utilities raise capital through the issuance of tax-free bonds.

Like their IOU counterparts, municipal gas utilities serve as a "reseller" to their retail customers. Typically, municipal gas utilities purchase gas supply and transportation rights rather than having any ownership in production or pipeline facilities.

c. Indiana Sales and Transportation of Gas

Movement toward deregulation of the gas industry has been synonymous with further unbundling of gas services by different providers, whether they have been interstate pipelines or local gas distribution companies (LDCs).[12] For the past several years, LDCs have been both merchants, providing bundled sales and transportation service to many of their customers, as well as transporters, moving gas through their systems for industrial and commercial customers that have purchased gas directly from producers or marketers. These transportation-only customers pay just a transportation fee to the LDC.

Because the degree of unbundling can be a rough measure of deregulation, the following tables and graphs compare historically the degree of unbundling in Indiana by its four largest LDCs. Sales figures are based on sales of gas made by LDCs to customers that purchase bundled service, which includes both the gas and transportation service. Transportation figures include only volumes of gas owned by end users that move through an LDC's system. Throughput figures include all volumes of gas moving through the LDC's system regardless of ownership. Degrees of unbundling increase as transportation volumes increase relative to the total throughput during a given period.

Table 4 presents sales and Table 5 presents transportation information for Citizens Gas, Indiana Gas Company, NIPSCO and SIGECO. These four companies collectively represent about 90 percent of the natural gas retail deliveries in the state. For more detailed information, see Appendix 2.

Table 4: Sales (Dth) for the Four Largest Gas Utilities in Indiana – 1997

Utility	Residential	Commercial	Industrial	Other	Total
Citizens Gas	26,392,624	14,934,080	6,923,412	374,100	48,624,216
Indiana Gas	48,208,746	19,435,857	13,499,071	-	81,143,674
NIPSCO	73,452,000	29,050,000	15,807,000	13,887,000	132,196,000
SIGECO	9,653,802	4,367,755	998,799	(194,892)	14,825,464

Source: IURC data requests

[12] Unbundling in the wholesale markets is the process whereby combined or "bundled" services are disaggregated into their component parts and sold separately. Customers have the ability to buy only those services they require, such as commodity, transportation, balancing services and/or storage.

Table 5: Transportation of Gas (Dth) by the Four Largest Gas Utilities in Indiana -- 1997

Utility	Commercial	Industrial	Other Sales	Total
Citizens Gas	2,168,530	6,976,993	-	9,145,523
Indiana Gas	-	42,778,546	-	42,778,546
NIPSCO	3,957,000	156,484,000	-	160,441,000
SIGECO	781,909	12,989,812	772,338	14,544,059

Source: IURC data requests

Table 6 reflects the percentage of total gas transported to the total gas throughput for each of the four utilities and for the four utilities combined. These percentages indicate the extent to which natural gas sales were unbundled for each of the last 10 years in Indiana. NIPSCO has had the highest total transportation to throughput rate with a 56 percent average over the last 10 years, followed by SIGECO, Indiana Gas and Citizens with 41, 24, and 17 percent total company transportation to total company throughput, respectively.

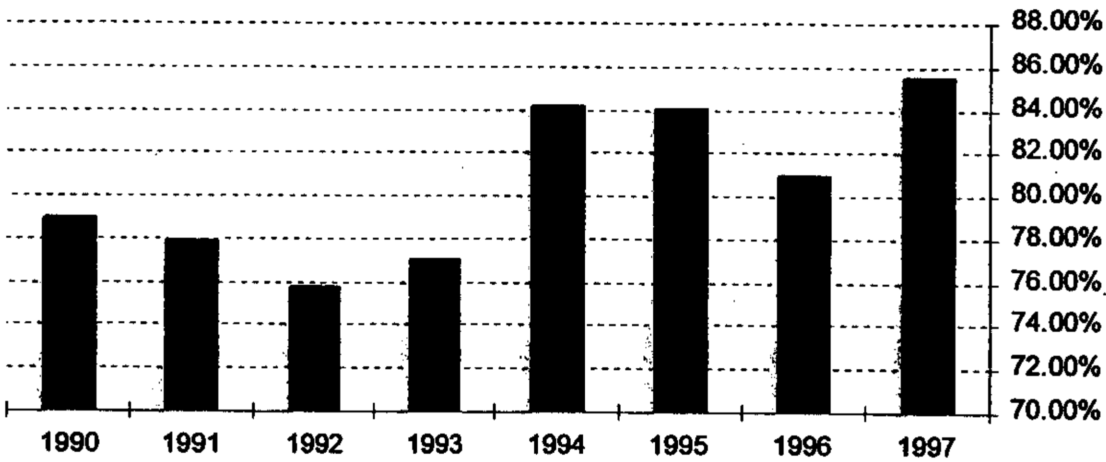
Table 6: Percentage of Gas Transported to Total Gas Throughput

% Total Transportation to Total Throughput	1997	1996	1995	1994	1993	1992	1991	1990	1989	1988	10 yr. Average
Citizens Gas & Coke Utility	15.8	9.8	19.7	23.2	17.4	11.8	21.6	16.6	16.9	18.7	17.1
Indiana Gas Company, Inc.	34.5	28.8	28.6	25.9	11.1	13.2	18.8	23.3	27.0	26.7	23.8
NIPSCO	54.8	54.2	58.6	60.2	59.2	57.4	55.8	55.5	50.4	49.2	55.5
SIGECO	49.5	38.0	43.7	42.9	40.3	37.3	38.5	41.7	41.5	40.0	41.4
Combined Weighted Average	45.0	41.4	45.1	46.4	41.8	40.7	42.1	43.0	40.9	40.5	42.7

SOURCE: Appendix 2, pages 3-7, which are responses to IURC data requests.

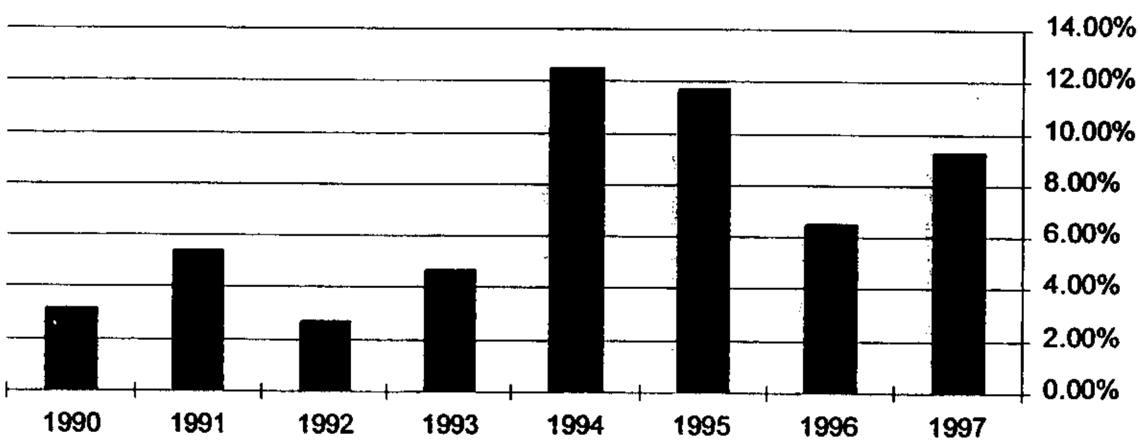
Bar graphs 1 and 2 depict total gas transportation, relative to total gas throughput, for the commercial and industrial sectors for the four utilities studied. These graphs show that use of unbundled services by industrial gas customers has been more extensive than use by commercial customers. Despite the drop in gas transportation from 1995 to 1996, there does not appear to be any discernable trend. Marketers began transporting gas in April 1998 for residential customers under the NIPSCO residential Customer Choice Program.

Bar Graph 1: Percent of Industrial Throughput: Transportation-Only Service



Source: See Appendix 2

Bar Graph 2: Percent of Commercial Throughput: Transportation-Only Service



Source: See Appendix 2

2. Indiana Gas Prices

Table 7 provides a comparison of average natural gas price by sector and state for 1997 and 1998. The price to Indiana residential and commercial customers is below the national average for both years.

Table 7: Average Price* of Natural Gas by Sector and State -- 1998 and 1997

	Citygate Price		Residential		Commercial		Industrial		Electric Utilities	
State	**1998**	**1997**	**1998**	**1997**	**1998**	**1997**	**1998**	**1997**	**1998**	**1997**
Alabama	3.08	3.86	7.27	8.01	6.48	7.03	3.36	3.65	2.66	2.72
Alaska	1.73	1.84	3.64	3.69	2.42	2.52	1.49	1.55	1.86	1.63
Arizona	2.48	3.16	7.47	6.94	5.62	5.11	3.51	4.09	2.82	3.90
Arkansas	3.02	3.31	7.28	6.27	5.14	5.12	3.65	3.73	2.32	3.14
California	2.30	3.05	6.85	6.29	6.78	6.79	4.23	4.65	2.87	3.83
Colorado	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n.a	2.75	3.15
Connecticut	5.24	5.46	10.20	10.33	7.37	7.92	4.90	5.32	2.73	2.90
Delaware	2.76	4.21	8.17	7.82	6.74	6.48	4.15	4.51	4.44	3.36
Florida	3.52	4.27	10.61	11.27	6.74	6.77	4.47	4.56	2.45	3.45
Georgia	3.48	4.09	6.25	7.14	5.81	6.58	5.34	5.42	2.10	3.71
Hawaii	5.90	6.88	19.9	22.62	13.95	15.20	n/a	n/a	n/a	n/a
Idaho	1.90	2.14	5.15	4.89	4.48	4.37	3.09	2.76	n/a	n/a
Illinois	2.82	3.19	5.03	5.89	4.69	5.46	4.12	5.55	2.29	2.59
Indiana	**2.42**	**3.14**	**6.09**	**6.13**	**5.39**	**5.39**	**4.27**	**4.31**	**3.23**	**3.72**
Iowa	3.52	3.51	5.3	5.64	4.35	4.93	1.23	3.97	3.25	3.68
Kansas	3.00	3.48	5.82	6.29	4.99	5.89	3.69	3.08	2.55	3.10
Kentucky	3.28	3.75	5.55	6.14	5.48	5.72	4.20	4.42	3.82	3.89
Louisiana	2.48	3.21	5.81	6.81	5.36	6.30	2.59	3.08	2.55	3.10
Maine	3.25	4.17	7.90	8.55	7.41	8.03	6.02	6.65	n/a	n/a
Maryland	3.46	3.70	7.55	7.66	6.24	6.37	4.81	n/a	3.36	4.59
Massachusetts	3.28	3.59	9.34	9.68	7.54	8.09	6.73	7.33	3.25	3.27
Michigan	2.90	3.17	4.87	4.94	4.74	4.81	3.86	4.11	0.69	0.62
Minnesota	3.05	3.47	5.17	5.64	4.46	4.99	3.10	3.41	2.72	2.31
Mississippi	n/a	3.54	n/a	5.88	n/a	5.16	n/a	3.58	2.47	2.99
Missouri	3.06	3.51	5.97	6.22	5.64	5.94	4.70	5.04	2.62	4.09
Montana	2.50	3.34	4.98	4.57	4.94	4.49	4.93	4.81	12.18	5.17
Nebraska	3.38	3.59	5.02	5.58	4.93	5.03	3.32	3.92	3.04	2.81
Nevada	3.07	3.48	6.73	5.75	5.71	4.97	5.95	7.14	2.28	2.13
New Hampshire	3.73	4.24	8.03	8.72	7.31	8.24	5.39	6.02	n/a	n/a
New Jersey	3.70	4.11	7.40	7.55	4.25	6.70	3.45	4.4	2.89	3.24
New Mexico	2.16	2.63	4.59	5.55	4.00	4.55	3.60	3.41	2.38	2.88
New York	n/a	n/a	n/a	9.94	n/a	7.26	n/a	5.41	2.98	3.14
North Carolina	3.60	4.03	8.02	8.91	6.66	7.49	4.30	5.23	3.92	6.89
North Dakota	2.89	3.34	4.73	4.28	4.11	3.97	3.14	3.13	n/a	2.93
Ohio	4.69	5.32	6.03	6.68	5.70	6.40	5.40	5.96	3.78	3.99
Oklahoma	2.58	3.27	5.57	6.00	5.33	5.73	3.97	4.45	3.21	3.75
Oregon	n/a	2.35	n/a	5.82	n/a	4.57	n/a	3.70	1.14	1.73
Pennsylvania	4.16	3.89	8.54	7.98	7.27	7.38	4.60	5.06	2.70	3.37
Rhode Island	3.55	4.00	8.90	9.22	7.80	8.15	4.16	4.51	3.33	3.38
South Carolina	3.32	3.71	8.13	8.74	6.74	7.00	3.51	3.88	3.68	4.71
South Dakota	3.29	3.60	5.25	5.16	4.28	4.29	3.32	3.95	n/a	n/a
Tennessee	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Texas	3.01	3.87	5.80	6.02	4.79	5.19	2.51	2.88	2.44	2.95
Utah	3.30	2.60	5.55	4.83	4.31	3.67	3.06	2.45	n/a	n/a
Vermont	2.71	2.04	6.28	6.08	5.18	5.18	2.98	3.13	2.91	3.57
Virginia	3.63	4.09	8.03	8.22	6.10	6.51	4.39	4.85	3.33	2.78
Washington	n/a	2.71	n/a	5.45	n/a	4.61	n/a	3.40	2.10	7.58
West Virginia	3.06	3.14	6.93	6.74	6.34	6.18	2.83	2.97	5.59	5.21
Wisconsin	3.24	3.52	6.06	6.56	5.06	5.58	4.13	4.32	2.81	3.26
Wyoming	n/a	3.25	n/a	3.93	n/a	3.49	n/a	3.40	8.62	12.45
Average	3.20	3.57	6.92	7.06	5.78	5.99	3.96	4.29	3.22	3.67

n/a = Not Available * (Dollars per Thousand Cubic Feet, the information is preliminary based on year-to-date information)

Source: US Department of Energy, Energy Information Administration, Natural Gas Monthly, August 1998 tables 20-24.

D. Recent Developments in Natural Gas

1. NIPSCO Alternative Regulatory Plan

NIPSCO was the first natural gas utility in the state of Indiana to make use of Senate Enrolled Act 637, which was signed into law on April 17, 1995. This Act, I.C. 8-1-2.5, allows energy utilities to propose alternative regulatory procedures (ARPs) in place of traditional cost-based regulation. Through the provisions of this Act, NIPSCO filed Cause Number 40342 on November 29, 1995, and sought to interject competitive forces into its business practices and provide unbundled gas distribution services to all classes of customers. The net effect of the proposed changes, which will be phased in over time, will be more service options for all of NIPSCO's customers with no loss of current service options. The Commission approved an amended settlement agreement in its order issued October 8, 1997, specifically addressing the following key issues:

1. New Services Tariffs. To effectuate the ARP, NIPSCO has proposed an array of new service offerings.

2. System-Wide Unbundling (Residential Pilot Program). NIPSCO will implement a system-wide unbundling program for the purpose of providing customer choice of gas suppliers. The program will be implemented upon approval by the Commission and be effectuated no later than December 31, 2004. Initially, a pilot program for residential customers will be limited, but later will be enlarged as determined by the participants to this proceeding. The purpose of the pilot program is to determine (1) the operational and administrative issues that will be raised in the process of unbundling NIPSCO's system; (2) the customers' response to customer choice; (3) the issues, if any, involving market segmentation; (4) the ability to provide safe, reliable and efficient services in an unbundled environment, and (5) the existence of barriers to entry and exit from an unbundled market. A key element to success of unbundling at the residential level is the mechanism for third-party suppliers to aggregate multiple small customer loads. During the transition period, NIPSCO agrees to proceed in incremental steps so as to minimize any transition costs. Also, NIPSCO agrees to give annual informational presentations to all interested parties on the progress of unbundling.

3. Maintain Merchant Function During Transition Period. NIPSCO maintains its right during the transition period to retain its merchant function (a provider of retail services) and serve as a supplier option for all customer classes. No later than six years from the effective date of the ARP, the parties will meet and revisit the continuing role of NIPSCO as a merchant in a fully unbundled environment.

4. Supplier of Last Resort. NIPSCO will remain the Supplier of Last Resort (SOLR). SOLR services may include backup natural gas supply (commodity), backup transportation capacity, appropriate storage resources and services related to delinquent accounts.

5. Maximization of Underutilized Upstream Core Portfolio Assets. During the transition period, NIPSCO will attempt to maximize the utilization of any underutilized upstream core portfolio assets. These assets are (1) contracted capacity for transportation and storage and (2) contracted gas supply acquired in order to provide reliable service to the utility's core market. NIPSCO will share with its core customers the recovered revenues of the underutilized assets at a level of 85% to core customers and 15% to NIPSCO.

6. Gas Cost Incentive Mechanism (GCIM). The parties to the settlement have agreed to a Gas Cost Incentive Mechanism that rewards and penalizes NIPSCO for its supply acquisition performance when compared to a market standard benchmark. The tolerance and sharing bands agreed to by the parties are established for an initial two-year period. At the conclusion of the two-year period, the appropriateness of the bands, the derivation of the benchmark and the GCIM calculations shall be subject to an annual review on a confidential basis.

7. No Recovery of Pilot Program Transition Costs. NIPSCO has agreed not to seek recovery of any transition costs resulting from the implementation of the two-year residential pilot program.

8. Implementation of Gas Marketing Affiliate Guidelines. The parties have agreed to a set of marketing affiliate guidelines that will be used to govern transactions between NIPSCO and any gas marketing affiliates. The term marketing affiliate shall mean a company, partnership or other entity within a corporate structure that includes a utility engaging in or arranging for an unregulated retail sale of gas and/or provides gas-related services.

9. Embedded Cost of Service Study. NIPSCO shall provide the parties with an embedded cost of service study for all services not subject to competition no later than six months after the end of the transition period and in no event earlier than January 1, 2000.

10. Earnings Test Applies. NIPSCO agrees that all revenues generated under the terms of the stipulation and agreement shall be subject to Indiana Code 8-1-2-42(g)(3)(C), the currently enforced earnings test in gas cost adjustment (GCA) proceedings before the Commission.

11. Rate 330 Sales Reviewed in GCA Proceedings. NIPSCO agreed to allow the UCC and its consultants upon request to inspect on a confidential basis, information regarding the sales under Rate 330, Large Volume Negotiated Sales Service, including related contracts and supply resources. The UCC will report if any of these sales have adversely impacted the GCA and whether further investigations are warranted.

On October 8, 1997, the IURC approved the NIPSCO Choice program. This alternative regulatory plan (ARP) was the first residential and commercial retail choice program to be offered by an Indiana gas utility. The first phase of the program was opened to customers in parts of St. Joseph County and includes South Bend, Mishawaka, Granger and surrounding areas. Up to 50,000 residential customers and 1,500 commercial customers were eligible to select alternative natural gas suppliers. NIPSCO conducted several "open houses" in conjunction with extensive advertising to encourage customer participation. Alternative suppliers (marketers), representatives of the Office of Utility Consumer Counselor and the IURC attended these open houses to answer questions and provide information to the customer. Despite these initial efforts, reaction by residential consumers was less than NIPSCO anticipated, with only 6.5% of the eligible residential customers enrolling in the program. The vast majority of the enrolled customers were served by NIPSCO's affiliate NESI.

Two main factors contributed to lower than expected participation by residential customers. First, most customers did not understand their current bill. This, in turn, made it difficult for them to understand how they might save by purchasing their natural gas from an alternative supplier. Second, the marketers were unable to "guarantee" savings since these savings would have been in comparison to the NIPSCO bill that fluctuates due to the Gas Cost Adjustment (GCA). Generally, gas costs represent 40% of a customer's total bill, and the remaining 60% of the bill is associated with gas transportation and other customer-related costs. Customers choosing an alternative supplier could only realize savings on the actual fuel usage portion of gas cost part of their bill, which is a relatively small percentage of the total gas costs' 40% share.

The response rate by commercial and industrial customers was much greater, reflecting a greater opportunity for those customers to realize cost savings.

Columbia Energy Services Corporation (Columbia); NESI Integrated Energy Resources Inc. (a NIPSCO affiliate); NICOR Energy, LLC; and Volunteer Energy Corporation were the only marketers to participate in the residential program. Lack of participation by marketers was attributed to several factors. First, marketers felt the Supplier Aggregation Service (SAS) fee, designed to help NIPSCO recoup the cost of administering the program, was too high. Second, marketers experienced a lack of flexibility on operational aspects of the program, such as requiring deliveries to specific points on the NIPSCO system and requiring marketers to pay storage costs. Marketers claimed these operational requirements limited their profit potential as well as their ability to produce savings for customers. Finally, marketers are sometimes reluctant to participate in a pilot program due to the small number of eligible customers. Without a sufficient number of customers the marketers cannot aggregate enough load to offset their costs and offer savings to the consumer. In February 1998, to improve participation by marketers, NIPSCO modified the program by discounting the SAS fee and improving flexibility in receipt point requirements.

In April 1998, alternative suppliers began transporting natural gas through the NIPSCO system and delivering it to customers in the pilot program. NIPSCO declined to make marketer statistics available at this time.

On June 25, 1998, NIPSCO filed a 30-day filing with the Commission requesting additional changes to the choice program to be implemented in the fall of 1998. This filing was approved by the Commission on August 12, 1998. Modifications for the marketers include flexibility in storage management; maintenance of the discount of the SAS administrative fee; and continuation of customer pooling under one aggregation contract. All the marketers participating in Phase 1 will continue to participate with the exception of Columbia. Columbia will continue to serve the customers it acquired in Phase 1, but will not participate in the future.

To increase participation by residential customers, NIPSCO's 30-day filing provided for continuing enrollment of residential customers until full subscription is reached; increasing the number of eligible customers to 80,000, effective August 1, 1998; and improving customer education materials. NIPSCO is currently working with the OUCC, the IURC and marketers to implement more automated customer sign-up procedures.

2. NIPSCO Industries/Bay State Gas Company Merger

On March 20, 1998, NIPSCO Industries petitioned the Massachusetts Department of Telecommunications and Energy (DTE) to merge Bay State Gas Company (Bay State) with NIPSCO Industries. Both companies contend that the merger will result in the following: 1) a five-year rate freeze, 2) reduced costs resulting from the elimination of duplicated positions, 3) savings due to growth in system sales, 4) gas supply-related savings from operating economies and efficiencies due to coordinated planning and management of each respective portfolio, 5) an earnings sharing mechanism and 6) access to more financing options.

Two merger options were proposed. The Preferred Merger Structure ("Preferred Merger") would reorganize Bay State as a wholly owned subsidiary of NIPSCO Industries, with each company continuing to operate as separate corporations with their own books and records, capital structures, management structure and boards of directors. Both companies believe that the Preferred Merger maintains effective accountability for their utility operations, and provides a less complex regulatory oversight structure.

NIPSCO Industries presently holds exempt holding company status under the Public Utility Holding Company Act of 1935 (PUHCA). As a condition of the Preferred Merger, the Securities and Exchange Commission may require NIPSCO Industries to relinquish its exempt status, which would impose significant reporting requirements on the company. In this event, NIPSCO Industries has requested that the DTE also approve the second option, Alternative Merger, which does not require SEC approval. The Alternative Merger would directly merge Bay State into NIPSCO Industries' primary gas subsidiary, Northern Indiana Public Service Company, which would operate Bay State as its Massachusetts division. The Massachusetts operations would have its own management structure distinct from its Indiana operations, but would not have a separate board of directors.

The purchase price of $550 million over the book value of $239 million results in an acquisition premium of $310 million, which does not include the transaction fees associated with the merger, estimated at less than $5 million for NIPSCO Industries. Bay State has incurred $1.78 million in merger costs through April 1998. Both companies' acquisition costs would be included in the acquisition premium. Bay State expects to amortize the total acquisition premium over 40 years. After a proposed five-year rate freeze, Bay State indicates it may seek recovery of the annual amortization of the acquisition premium expense in future rate proceedings to the extent it is offset by demonstrable merger-related savings. All hearings have concluded, and briefs and reply briefs have been filed. The SEC is not expected to act on the merger until the Massachusetts DTE issues its ruling.

In an effort to intensify the competitive gas market in Massachusetts, the Massachusetts DTE directed the state's gas companies to commence a collaborative process to develop common principles and procedures for unbundling gas utility services. Companies were unable to agree on the treatment of upstream pipeline capacity, and the DTE has not ruled on this issue. All companies have made filings reflecting unbundled service offerings. Only Bay State has implemented a pilot program that extends customer choice to residential customers. Currently, 26,700 customers take service under this pilot.

3. ProLiance

ProLiance is an Indianapolis-based marketer of energy and related services that was formed in March 1996 by affiliates of Indiana Energy and Citizens Gas, with the purpose of assuming the gas supply and portfolio administration services for the two utilities. ProLiance administers the utilities' transportation and storage contracts, and procures gas and transportation in the marketplace on behalf of the two utilities. ProLiance also develops supply plans for the utilities' review, schedules supply deliveries to the city gate, and develops capacity portfolio plans for the utilities' review. Additionally, ProLiance provides gas sales, administration, and marketing services to the customers of the utilities' marketing affiliates.

In Cause No. 40437, 20 industrial customers served by the two utilities petitioned the Commission to disapprove the contracts and agreements between Indiana Gas and Citizens Gas relating to ProLiance. The petitioners were later joined by the Office of the Utility Consumer Counselor and the Citizens Action Coalition. For the petitioners, the central issue was whether the contract between Indiana Gas and ProLiance should be disapproved as not in the public interest for the following reasons: 1) the lack of competitive bidding and the reasonableness of contract terms; 2) alleged violation of the terms of a prior settlement agreement regarding capacity release; 3) the unapproved transfer of alleged utility assets and functions; 4) the misallocation of the benefits of operational consolidation of the utilities; 5) the circumvention of Commission regulation and oversight; and 6) alleged anti-competitive effects on the marketplace.

The complaint was originally filed on March 29, 1996, and amended on June 7, 1996. Public evidentiary hearings were held from October 3 through October 9, 1996. On September 12, 1997, the IURC denied the complaint. In its order, the Commission ruled that the agreements by which the utilities created ProLiance are in the public interest in part, because efficiencies gained by consolidating the gas supplies of the two utilities have caused gas rates to decrease for each utility. The Commission advised the utilities, however, that the Commission would be taking some of the concerns raised in the complaint into account when scrutinizing future gas cost adjustment filings.

The Commission's Order was appealed by the Office of the Utility Consumer Counselor, the Citizens Action Coalition and the Industrial Customers. Some of the issues under appeal included: 1) the IURC erred by authorizing an arrangement by Indiana Gas and Citizens Gas that circumvented the regulatory scheme by unilaterally deregulating portions of utility service and implementing an alternative regulatory plan; 2) the IURC erred by applying the incorrect standard for reviewing the public interest; 3) whether the IURC has jurisdiction to regulate ProLiance within the scope of its common enterprise with Indiana Gas and Citizens Gas; and 4) whether the transfer of gas supply contracts, functions and personnel from Indiana Gas to ProLiance required prior approval by the IURC.

The Appellees have filed their briefs and the Appellants have filed their reply briefs. The case was transmitted to the Court for decision on June 22, 1998.

The Antitrust Division of the United States Department of Justice (DOJ) is investigating ProLiance for possible violations of Section 1 of the Sherman Act.[13] In August 1998, Indiana Gas, Citizens and ProLiance received "civil investigative demands" from the DOJ, which typically means the DOJ will be examining the matter closely. The DOJ also issued subpoenas to Indiana Gas, Citizens and ProLiance as part of the investigation.

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[13] Sword, Doug, "Antitrust probe looks at utilities' operations," The Indianapolis Star, August 22, 1998, p.1.

IV. SUMMARY OF STATE COMPETITION INITIATIVES

A. State Competition Initiatives in Electricity

Electric utility restructuring continues to be an active issue in most states since the 1997 Energy Report to the Regulatory Flexibility Committee of the Indiana General Assembly. In California, Rhode Island and Montana, some retail customers now have access to alternative electricity suppliers as a result of restructuring programs. Further, utilities in Idaho, Iowa, Washington and Oregon have initiated pilot programs that allow select groups of retail customers access to alternative electricity suppliers, although industry-wide restructuring is still under debate.

During the 1998 legislative session, three states passed extensive restructuring bills, Illinois, Connecticut and Virginia. The Illinois legislation will be discussed in more detail in the next section. Connecticut's legislation opens customer choice in 2000. The Connecticut Department of Public Utility Control is empowered to make necessary regulatory changes in adherence to a strict time schedule. The Virginia legislation, which would begin the transition to customer choice in 2002, also empowers the State Corporation Commission to develop and eventually implement an industry-wide restructuring plan.

A number of other state legislatures considered restructuring legislation that was either defeated or left pending at the end of the legislative session. Most other states are still in the process of addressing the electric utility restructuring issue. Activities range from finalizing the details of a restructuring plan that can be used as a basis for legislative action to the establishment of task forces to study the issue.

Two states, California and Massachusetts, are facing political challenges to their enacted restructuring laws. In both states, organizations have initiated efforts to repeal the state's current restructuring law by placing a proposition on the ballot of the general election in November. It is unclear at this time whether the issue will make the ballot in either state or what the outcome may be.

The following discussion highlights some of the significant legislative and commission actions in Indiana's four neighboring states and throughout the United States during the previous twelve months. Appendix 3 presents a summary of restructuring activities by state.

- Illinois -

On December 16, 1997, Illinois Governor Jim Edgar signed three measures that made Illinois the 14th state to have either a regulatory or legislative restructuring mechanism in place. The first bill, Electric Service and Customer Choice and Rate Relief Act of 1997, mandates a 20 percent residential rate cut for Commonwealth Edison and Illinois Power and a 5 percent cut for other Illinois utilities until rates reach the Midwest average. The rate reductions take effect August 1, 1998.

Direct access to alternative electricity suppliers will begin in October 1999 for large industrial customers. One-third of the commercial and industrial customers with demand less than 4 MW will get direct access to alternative suppliers on October 1, 1999. The remaining commercial and industrial customers will have direct access by 2000. Residential customers will receive full access by May 1, 2002.

The legislation does not address any legislative or regulatory method of calculating stranded costs, relying instead on a lost revenue approach with oversight by the General Assembly.

The first of two "trailer" bills applies to Central Illinois Light (CILCO), which opposed the 5 percent rate cut because its rates are already below the Midwest average. The trailer bill allows CILCO to implement the cut over a longer period: 2 percent on August 1, 1998, 2 percent on October 1, 2000 and 1 percent on October 1, 2002. The trailer also allows CILCO to earn an equity return as high as 16 percent, rather than 12 percent as set for most of the other utilities, before profits must be shared with ratepayers.

The second trailer addresses the effects of accelerated depreciation of utility assets on municipal tax revenues. The measure allows utilities to depreciate assets in preparation for competition. However, to prevent a rapid decline in municipal tax revenues due to the accelerated depreciation schedule, the trailer bill places a moratorium on asset reevaluation for 1997-1999.

Since the Electric Service and Customer Choice and Rate Relief Act of 1997 was enacted, the Illinois Commerce Commission (ICC) has set a rapid pace in implementing the legislation. The ICC has made decisions on a wide range of issues, including strengthening electric service reliability standards; requiring electric utility subsidiaries to compete on their own rather than using the marketing resources of the holding companies; approving the funding mechanisms to support basic residential energy service and environmental research and protection; and advising approximately 400 Illinois municipalities on adjusting to the effects of rate reductions on local tax revenue.

In addition, the ICC selected Peter Hoffman of Deloitte & Touche as a neutral fact finder to establish the market value of electric power and energy. The ICC has facilitated discussions necessary to ensure that the services provided by the utilities allow the transmission and distribution system to function properly with the advent of consumer choice. Further, the Commission initiated proceedings to establish rules defining the way utilities will be structurally organized in a new competitive environment.

Other major items pending on the Commission's fast track are:

1. Establishing rules requiring utilities and alternative suppliers to disclose the sources of electricity supplied and emissions attributable to those sources.
2. Establishing standards for the entry of alternative retail electric suppliers into the Illinois market. The standards must balance the goals of promoting competition and protecting small commercial and residential customers from unscrupulous operators.
3. Reviewing proposals that will allow electricity to be priced at different levels throughout the day to reflect the true, real-time cost of producing and obtaining power.

The broad changes in the electric service industry mandated by the new legislation will result in the ICC's undertaking an unprecedented public education program designed to inform average consumers and small businesses alike about selecting alternative energy suppliers.

To help ensure that consumers are well-informed, the legilation requires retail electric suppliers to provide potential customers with written information disclosing the prices, terms and conditions of the services offered. Retail suppliers will also provide the customer with itemized billing statements, and at least once a year, an additional statement that discloses average monthly prices and the terms and conditions of the products and services sold to the customer.

- Kentucky -

As a low-cost state, Kentucky previously showed little interest in restructuring its electric utility industry. However, on April 7, 1998, Governor Paul Patton signed House Joint Resolution No. 95, which creates an Electricity Restructuring Task Force consisting of 10 members from the General Assembly and 10 from the executive branch, to study electricity restructuring. The task force will study electric industry deregulation over the next 18 months to prepare for the next biennial legislative session in 2000.

- Michigan -

Legal battles continued to plague the Michigan Public Service Commission (MPSC) as it tries to implement its June 5, 1997, restructuring plan. The plan requires each utility to make available to all customers on a first-come, first-served basis a block of direct-access capacity equivalent to about 2.5 percent of the utility's load. Under the provisions of the MPSC's order, utilities will be required to add another 2.5 percent block each year through 2001. By 2002, any customer in the state that wants choice of supplier will be eligible to receive it.

In August 1997, the Michigan Attorney General, the Residential Ratepayer Consortium and the Association of Business Advocating Tariff Equity (ABATE) petitioned the Ingham County

Circuit Court to stop deregulation proceedings until the MPSC determines if it has authority to mandate direct access.

In January 1998, the Michigan Court of Appeals affirmed the authority of the MPSC to order experimental retail wheeling in the state. The order was in response to an appeal filed by Consumers Energy, Detroit Edison and the Attorney General arguing that the MPSC lacked statutory authority to implement a direct-access program and that compelling a utility to participate in such a program would relieve the utility of its obligation to supply existing customers with power from its own resources.

On February 11, 1998, the MPSC issued an order clarifying its original restructuring order and directed Consumers Energy and Detroit Edison to file revised tariff sheets. On February 13, 1998, Consumers Energy and the Attorney General filed notices with the Michigan Court of Appeals that they intended to challenge the MPSC's restructuring orders. The Attorney General stated that the appeal was filed because he did not believe the restructuring plan created a competitive generation market that would reduce rates for Michigan's customers. This appeal is still pending.

On March 6, 1998, ABATE filed charges with the MPSC that Consumers Energy and Detroit Edison failed to comply with the MPSC's restructuring orders. In the petition ABATE alleged that the open-access rates contained in Detroit Edison's tariffs exceeded those authorized by the MPSC and required conditions of eligibility for an alternative power supplier. ABATE had similar complaints about Consumers Energy.

Finally, in April 1998, Consumers Energy offered 300 MW of retail capacity for bidding under the MPSC's retail wheeling program, with an additional 150 MW to be made available for direct access each year until 2002. In 2002, all Consumers Energy customers will be able to choose their electric supplier. Detroit Edison announced it would offer 225 MW blocks of capacity for direct access over five separate periods, culminating in 1,125 MW after January 1, 2001. It is too soon to tell what the customer response to these programs will be.

- Ohio -

In March 1998 companion bills were introduced in the Ohio House and Senate to open the electric utility industry to competition by January 1, 2000. The legislation was designed to create "retail marketing areas." Customers would be aggregated into groups of 100,000 during a five-year transition period ending December 31, 2004. Power suppliers could then bid to serve the "retail marketing areas," with the Ohio Public Utilities Commission selecting the lowest bid.

Ohio's eight investor-owned utilities would be given the opportunity to recover per-kilowatt-hour transition revenues, which would compensate them for a portion of the difference between their current cost to generate electricity and the current 3.96 cents/kWh regional market cost. The transition charges would decline over the five-year period, ending December 31, 2004.

In May 1998, the restructuring efforts were dealt a setback when primary election voters rejected a proposed one-cent sales tax initiative to help finance the state's public schools. The defeat resulted in the tax issue being sent back to state legislators for further study. The legislators are trying to comply with an Ohio Supreme Court order to finance public schools with less reliance on property taxes.

Ohio electric utilities are directly affected by the school funding debate because they pay some of the highest property taxes in the state and are assessed a higher rate than other businesses. Because utilities contribute so heavily to public school financing, the deregulation issue has been linked with school funding from the start.

- California -

Throughout 1997 and early 1998 the California Public Utilities Commission (CPUC) proceeded with implementation of its electric utility restructuring plan. Customer choice, originally scheduled to begin January 1, 1998, was finally implemented on March 31, 1998. Computer problems related to the operation of the ISO and Power Exchange caused the delay in customer access.

The CPUC addressed a variety of important issues prior to the opening of customer choice, including the following:

1. Development and implementation of a customer education program.
2. Development of certification and registration requirements for aggregators, marketers and brokers.
3. Development of rules for accessing customer load information.
4. Establishment of consumer protection measures.
5. Development of rules governing the relationship between utilities and their affiliates in a competitive market.
6. Establishment of a process for recovering transition costs.

The CPUC has had to address some problems that have arisen because of customer choice. For example, during the spring of 1998 the CPUC launched an investigation of Boston-Finney, one of the 277 energy service providers that had registered with the CPUC to sell, aggregate, market or broker electricity to residential and small business customers. The investigation was begun after consumers complained that Boston-Finney misrepresented the nature of service and level of savings which it could provide to customers, had been dishonest and possibly engaged in fraud and was not financially or operationally capable of ultimately offering the service for which it was soliciting customers. After a thorough investigation the CPU removed Boston-Finney from its registered energy service provider list and banned the company from participating in the California market.

Also in March 1998, the CPUC's Office of Ratepayer Advocates (ORA) and The Utility Reform Network (TURN) filed a cease and desist motion, stating that a print ad promoting PG&E Energy Services had violated the rules governing the relationship between a parent utility company and its affiliates. The CPUC agreed with ORA and TURN and initiated a more detailed investigation before setting the penalty for PG&E. The CPUC may impose penalties of not less than $500 but not more than $20,000 for each offense; each print ad is considered one offense. The final result of this investigation is still pending.

- Massachusetts -

Although not without some setbacks, the Massachusetts Department of Telecommunications and Energy (DTE) continues the process of implementing customer choice. In May 1998, Western Massachusetts Electric (WMECO), a subsidiary of Northeast Utilities, asked DTE for permission to remove the price cap on standard offer power in hopes of attracting suppliers.

Massachusetts regulators created the "standard offer" as a way to ease customers into competition. Utilities must provide electricity at a standard price for seven years to any customer who does not choose a competitive supplier. Regulators and lawmakers pushed for the electricity to be priced low so that customers would experience immediate savings under deregulation.

WMECO solicited bids from suppliers to meet the standard offer demand at no higher than 3.2 cents/kWh. No bids were submitted. WMECO sells electricity to its standard offer customers at 2.8 cents/kWh. Other utilities also received no bids when soliciting for standard offer power. Currently, utilities are using their own generation to meet these needs but it is unclear who will be responsible for providing standard offer power once the utilities divest their generation assets.

On another deregulation front, Massachusetts utilities are using legal strategies and public campaigning to block an attempt to repeal the state's restructuring law. Boston Edison and New England Electric System, along with associations representing power marketers, industrials and retail businesses have joined together to back a political committee called Keep the Electric Rate Reductions. The committee is campaigning against a November ballot question that would put an end to retail choice in Massachusetts.

The Campaign for Fair Electric Rates, a consumer group, collected the necessary 32,000 signatures to place the repeal question on the ballot. The group opposes the deregulation law because it allows 100% recovery of utility stranded costs.

The pro-competition group's first line of attack has been through the court system. The group recently argued before the Massachusetts Supreme Judicial Court that the restructuring law cannot be overturned through a referendum question. The pro-retail choice group also has accused the Campaign for Fair Electric Rates of making unlawful changes to petitions used to gather the required signatures. If the pro-competition group loses in court, it plans to conduct a grass roots political campaign to defeat the referendum.

- New Hampshire -

A U.S. District Court has rejected a new request for delay by New Hampshire state officials, instead explicitly expanding a preliminary injunction against a state restructuring plan to include all utilities in the state. Under the June 5, 1998, ruling, Judge Ronald Lagueux confirmed that plans by the New Hampshire Public Utilities Commission (NHPUC) to begin retail choice were "frozen" until he hears a case on the merits of the state's market-based stranded cost methodology, probably in November 1998.

In particular, he said the NHPUC cannot require utilities to file restructuring compliance plans and cannot force them to implement plans already filed. At the same time, Lagueux said his order would not block the PUC from approving plans in which utilities voluntarily agreed with the state on the terms for restructuring.

Lagueux had originally placed an injunction on the state's restructuring plan for Public Service New Hampshire in May 1997, saying he believed the state's approach was unconstitutional and likely to be struck down in his final ruling.

- Pennsylvania -

The Pennsylvania Public Utility Commission (PPUC) concluded all of its electric restructuring cases but now faces legal challenges on stranded cost disallowances. Both PP&L Resources and Allegheny Energy have filed suits in state and federal courts seeking reconsideration of their allowed stranded cost recovery.

On July 15, 1998, PP&L filed suit at the U.S. District Court, claiming violations of the U.S. Constitution; and at the Pennsylvania Commonwealth Court, charging misapplication of the state's Electricity Competition Act. A separate action asks the state court to halt implementation of retail competition, because the PPUC has misinterpreted the act. Retail access is scheduled to start in January 1999, covering two-thirds of customers, and extend to the remainder in 2000.

PP&L complained that the PPUC used an inappropriate price forecast, which made its plants seem more valuable in the competitive market, thereby reducing stranded costs. It also says the commission set an arbitrarily high "shopping credit" of 3.73 cents. That represents the generation portion of rates that are open to competition, so a higher credit gives marketers a bigger opportunity to provide savings, and would hurt the utility's attempt to retain customers.

Allegheny Energy has filed suits in state and federal courts, seeking to increase its recovery of stranded costs in Pennsylvania. Allegheny, which operates as West Penn Power in the state, asked for $1.5 billion, but the PPUC granted only $524 million. The company requested a new hearing, pointing out that West Penn charges the lowest rates in Pennsylvania, averaging 5.7 cents/kWh, and that much of its stranded cost burden stems from independent power contracts, which were mandated by federal law.

But the PPUC rejected the request, stating "The majority of West Penn's petition merely reiterates arguments raised and already decided" in the original restructuring case. Part of the argument was that the PPUC should calculate lost revenues in determining stranded costs, instead of merely estimating the value of assets, such as power plants.

Following the PPUC rejection, Allegheny filed suit in the U.S. District Court for the Western District of Pennsylvania and in state Commonwealth Court. The federal suit alleges unconstitutional taking of property, based on the PPUC's denying recovery of $200 million in independent power costs, from federally-mandated contracts. The PPUC decision also denied Allegheny the full rate recovery that was granted earlier by the FERC on its purchases from the Bath County Pump Storage plant in Virginia.

Further, transmission and distribution rate caps in the restructuring ruling deny the company full recovery of T&D, according to Allegheny. In the Pennsylvania court case, Allegheny claims that it is not being granted the recovery due to it under the state's Electricity Competition Act.

Cases filed by both PP&L and Allegheny are all still pending at this time.

B. State Competition Initiatives in Natural Gas

The gas industry has been competitive for years at the wholesale and large end-user level, as customers routinely purchase their gas supplies and other load-managing services in the marketplace. The American Gas Association (AGA) estimates that 90 percent of large-volume natural gas customers have the ability to select their own natural gas supplier, and that 40 percent of commercial customers either now can, or will soon be able, to choose their own gas supplier (see Appendix 4).

Until 1996, customer choice options were largely limited to industrial, electric utility and large commercial customers. During the 1996 through 1998 period, however, customer choice options were made increasingly available to residential customers as the gas industry continues its evolution to a deregulated market. There has been a significant increase in residential pilot programs where customers are permitted to choose their own supplier. To serve the market in an efficient manner, these customers are aggregated by marketing companies, with the incumbent gas utility delivering the gas to the customers' homes.

Currently, twenty-one states and the District of Columbia have gas residential pilots that are either underway or proposed. California, Georgia, Iowa, New York and Pennsylvania have initiatives that provide or will provide all customers with the ability to choose their own supplier. Similarly, utilities in Maine, Massachusetts, Montana, New Mexico, Ohio and Oklahoma have proposed or implemented programs that provide all their customers with the ability to choose suppliers. Taken together, these programs will permit 31 percent of United States households to purchase their gas from a non-utility supplier. Combining this percentage with that for industrial and commercial customers, it is possible that more than 70 percent of gas consumed today could be purchased from non-utility sources. As more programs are proposed and adopted, the percentage of customers selecting their supplier is expected to grow.

These initiatives and pilots present many issues and challenges for utilities, regulators, customers and marketers. Issues that must be considered include the design and administration of pilot programs; contractual relationships with marketers; a utility's obligation to serve and the resulting cost of service; designing new balancing services; establishment of marketing rules and regulations; and allocation of upstream storage and pipeline capacity. Because gas utilities vary as far as system design and customer base, there are many types of pilot programs available (see Appendix 5).

V. FEDERAL LEGISLATIVE UPDATE

The major development in federal restructuring legislation in 1998 was the release of the Clinton administration's long-awaited Comprehensive Electricity Competition Plan. Secretary of Energy Frederico Pena presented the legislation to Congress in late June. See Appendix 6 for a summary of this bill and other major restructuring legislation introduced during this Congress.

The primary goal of the bill is to promote competition when it will benefit consumers. The Department of Energy estimates annual savings on energy expenditures at $20 billion, through direct and indirect savings arising from the lower cost of other goods and services. The DOE projects a family of four will save $232 annually.

The bill's other objectives are to improve the environment through market forces, renewable energy and nitrogen oxide caps; strengthen service reliability; and assist and protect consumers through a public benefits fund and required information disclosure by suppliers.

In November 1997, Senator Dale Bumpers introduced S.1401, The Transition to Electric Competition Act of 1997, which was a revised version of his earlier bill, S. 237. The new bill removed the "grandfathering" of state competition initiatives, and added repeal of Section 210 of PURPA, mandatory power purchases.

Other bills introduced in the House and Senate since last year's report included two environmental bills (H.R. 2909 and H.R. 3548) and two bills concerning tax-exempt utility financing (H.R. 3927, which restricts use of tax-exempt financing by government-owned utilities; and S. 1483, which allows municipal utilities to participate in open access without losing tax-exempt status on current bonds). Another bill, H.R. 3976, repeals PUHCA and replaces it with the Public Utility Holding Company Act of 1998, designed to support the continuing need for regulation and customer protection.

VI. EPA ACTIVITY

On November 7, 1997, the U.S. Environmental Protection Agency (EPA) published a proposal to reduce oxides of nitrogen (NOx) in 22 midwestern and eastern states, including Indiana. The rule is intended to reduce smog in the northeastern United States by reducing NOx emissions in the Midwest; the theory is that NOx emissions from the Midwest travel hundreds of miles and are deposited in the East and Northeast. This hypothesis is controversial even today, and many parties have couched their replies to the EPA-proposed rule in terms of reducing their local ozone problems. Indiana's Department of Environmental Management (IDEM) reply to the EPA-proposed rule states: ". . . we are confident that when Indiana and our nearby neighbors solve our respective ozone problems, our contribution to downwind states will be insignificant."[14]

The EPA's proposed rule would require an 85 percent reduction in NOx from 1990 levels by the year 2002. In general, midwestern utilities find this level of reduction to be too great, given the large costs involved. For example, AEP estimates it would cost $1.6 billion to comply with the EPA proposal, compared to $963 million for a 65 percent reduction level.

In a letter to the President, Governor Frank O'Bannon stated:

> We are very concerned that wholesale adoption of EPA's original proposal will result in unnecessary social and economic costs, undercut state efforts, fracture a cooperative approach, and engender lawsuits and delays, not clean air.[15]

In their response to EPA's proposed rule, IDEM stated:

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[14]Cover letter of IDEM's response to EPA's proposed rule, Re: Supplemental Notice of Proposed Rulemaking Regarding Regional Transport of Ozone, June 25, 1998.

[15]Letter to William J. Clinton, President of the United States, Re: the U.S. EPA's November 1997 clean air proposal, Office of the Governor, Indianapolis, Indiana, June 25, 1998.

> The proposed compliance date of 2002 for that level of control is extremely aggressive and may risk power reliability and cause onerous and expensive disruptions as plants across the country pursue limited technological and human resources to accomplish the improvements. Such a level and timeframe would require retrofitting a large number of sophisticated control devices on electric power plants throughout the eastern United States. We believe EPA's 2002 timeframe strains the ability of the electric utility industry and related businesses to complete this work responsibly. EPA has also not investigated the critical question whether electricity reserves are available to compensate for downtime associated with the installation of a large number of control devices.

In its reply to EPA, IDEM proposes the following alternative:

- the equivalent of a 65% reduction for power plants from 1990 levels by the year 2003
- an effective, easy-to-implement regional NOx emission trading system
- air quality assessments for the new ozone standard by the year 2001
- complete air quality plans by the year 2003
- EPA action in the event of failure by the state to perform.

The EPA is expected to issue the final rule in the fall of 1998.

VII. RELIABILITY CONCERNS

A modern electric power system can be thought of as one large machine. All components are physically connected, and all can be dramatically affected by events elsewhere in the system. Although there are many devices to prevent them, blackouts can be triggered in a fraction of a second, causing serious damage to the power system and resulting in a loss of power to some areas for days. To help ensure system reliability, the industry has developed a high level of cooperation and coordination among private companies. With restructuring and competition forthcoming, the question now being debated is how electric utilities will maintain the high level of cooperation and coordination necessary for reliability while simultaneously providing greater access to the transmission system and competing for customers.

a. Electric System Reliability Task Force

In the electric industry restructuring debate, one overarching message continually arises: no matter what, reliability must be maintained.[16] Partly in response to two massive power outages

[16] A simple definition of reliability is that it is the degree of assuredness with which the utility provides uninterrupted service to customers.

that cascaded through the Western power grid in the summer of 1996, the Department of Energy formed the Electric System Reliability Task Force. Its mission is to explore how reliability can be maintained and even improved in the transition to and the final structure of a competitive industry. The Task Force, chaired by former Congressman Philip Sharp, issued a position paper in November 1997, an interim report in March of 1998, and two more technical reports in May of 1998.[17] It is expected to issue its final report sometime in the fall of 1998.

The main conclusion of the Task Force's March report was that independent system operators should cover as large an area as possible, and should be implementers rather than creators of reliability standards. The report discussed many benefits to a large ISO: reducing the amount of "pancaking" or layering of transmission charges that would normally cross several smaller transmission systems; improving market efficiencies and promoting competition; and internalizing unscheduled loop-flows within the broad ISO.

b. North American Electric Reliability Council

Of course, everyone supports the general concept of reliability. The tougher questions are how and who will provide reliability in the future. The North American Electric Reliability Council (NERC), the voluntary industry group that oversees reliability concerns at the present time, has been studying these issues. In 1997, NERC formed a blue ribbon panel of outside experts to perform a study and recommend a new structure for itself. This panel issued a report in December 1997.[18] On July 9, 1998, the NERC Board of Trustees approved a series of recommendations that will reform it into the North American Electric Reliability Organization (NAERO), a new self-regulating reliability organization. The transition will begin in January 1999 when nine independent members are elected to the NERC Board. This expanded, more independent Board will govern NERC until:

1. U.S. and Canadian governments provide for appropriate grants of authority to a self-regulating reliability organization (SRRO) to set standards, enforce compliance, and collect funds (with a similar grant of authority from the government of Mexico to follow)

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[17] Maintaining Bulk-Power Reliability Through Use of a Self-Regulating Organization: Position Paper, November 6, 1997; The Characteristics of the Independent System Operator, March 10, 1998; Technical Issues in Transmission System Reliability, May 1998; Ancillary Services and Bulk-Power Reliability, May 1998; respectively.

[18] Reliable Power: Renewing the North American Electric Reliability Oversight System, NERC Electric Reliability Panel, December 22, 1997.

2. NAERO applies for and is approved as the only SRRO by the appropriate regulatory authorities in the U.S. and Canada

3. Funding of NAERO is decoupled from the Regional Reliability Councils.

After these conditions are satisfied, all but the nine independent members of the Board will step down and NAERO will be governed by an all-independent Board. The current Board also approved the following membership guidelines:

- System operator organizations (including control areas, ISOs, and security coordinators) and the Regional Reliability Organization in which they operate are required to become members of NAERO

- All organizations that have either a direct physical or commercial interaction with the bulk electric system may become members of NAERO

- Public interest groups may become members of NAERO

- Government regulators may be nonvoting members of NAERO.

Membership in NAERO provides the opportunity to serve on one of its committees and to vote for the independent directors.[19]

[19]This information is taken from Highlights and Summary of Action, Board of Trustees Meeting, North American Electric Reliability Council, July 9-10, 1998, Chicago, IL.

VIII. ACKNOWLEDGEMENTS

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LIST OF ACRONYMS

ARP	Alternative Regulatory Plan
CAC	Citizens Action Coalition
CPU	California Public Utility Commission
DOE	Department of Energy
DSM	Demand-Side Management
FERC	Federal Energy Regulatory Commission
G&T	Generation and Transmission
GCIM	Gas Cost Incentive Mechanism
I&M	Indiana Michigan Power Company, subsidiary of AEP
ICC	Illinois Commerce Commission
IMPA	Indiana Municipal Power Agency
IOU	Investor-owned Utility
IPL	Indianapolis Power and Light
IRP	Integrated Resource Plan
ISO	Independent System Operator
IURC	Indiana Utility Regulatory Commission
kWh	Kilowatt Hour
LDC	Local Distribution Company (gas)
MPSC	Michigan Public Service Commission
NERC	North American Electric Reliability Council
NHPUC	New Hampshire Public Utility Commission
NIPSCO	Northern Indiana Public Service Company
OUCC	Office of Utility Consumer Counselor
PPUC	Pennsylvania Public Utility Commission
PSI	PSI Energy
PSNH	Public Service New Hampshire
PUHCA	Public Utility Holding Company Act 1935
PURPA	Public Utility Regulatory Policies Act 1978
PX	Power Exchange
REMC	Rural Electric Membership Cooperative
SEC	Securities and Exchange Commission
SIGECO	Southern Indiana Gas & Electric Company
SOLR	Supplier of Last Resort
T&D	Transmission and Distribution

X. GLOSSARY

Affiliate: A company, partnership or other entity with a corporate structure that includes a utility engaging in or arranging for an unregulated retail sale of gas or electric energy or related services.

Aggregator: An entity that pools customers into a buying group for the purchase of a commodity good or service.

Alternative Regulatory Plan (ARP): In contrast to cost-of-service regulation, alternative regulatory plans are designed to allow the utility more flexibility in pricing energy to customers. ARPs may also contain provisions to streamline the regulatory approval process.

Ancillary Services: Services that must be provided in the generation and delivery of electricity. As identified by the FERC, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and economic dispatch of plants); contractual arrangements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

Broker: An agent for others in negotiating contracts, purchases or sales of electricity and associated services without owning any transmission or generation facilities. Unlike a marketer, a broker does not take title to the electricity being bought or sold.

Capacity: The size of a plant (not its output). Electric utilities measure size in kilowatts or megawatts and gas utilities measure size in cubic feet of delivery capability.

Citygate: A point of delivery to the gas local distribution company from the pipeline.

Convergence Mergers: In the context of energy, mergers between gas and electric utilities.

Cooperative: A business entity similar to a corporation, except that ownership is vested in members rather than stockholders and benefits are in the form of products or services rather than profits.

Cost-of-Service: A term related to the current methods of regulating utilities (both gas and electric). A cost-of-service study analyzes a utility's average costs (also called embedded costs) of facilities and expenses in relationship to its revenues to determine rates (prices) for the customer. This is generally referred to as cost-of-service ratemaking or cost-of-service pricing.

Dekatherm (Dth): A unit of heating value equivalent to 1 million Btus.

Demand-Side Management (DSM): Conservation resource planning that considers factors affecting energy usage for each customer class; generally designed to reduce or shift load.

Distribution: The component of a gas or electric system that delivers gas or electricity from the transmission component of the system to the end-user. Usually the energy has been altered from a high pressure or voltage level at the transmission level to a level that is usable by the consumer. Distribution is also used to describe the facilities used in this process.

Earnings Test: An evaluation conducted as part of generating fuel cost adjustments and all gas cost adjustments to determine if the proposed change in fuel or gas costs would result in a utility earning in excess of its allowed net operating income. The actual evaluation is complex, but if the utility is found to be earning more than allowed, the excess revenue is returned to the ratepayers.

Gas Cost Adjustment (GCA): A formal and summary proceeding held quarterly or semi-annually by the IURC for natural gas utilities which allows these utilities to increase or decrease rates based on changes in the price of gas purchased from various sources. Rates are projected for three or six months into the future and "reconciled" from the past with costs from comparable time periods and an "earnings test" is part of the process.

Generation: The process of producing electricity. Also refers to the assets used to produce electricity for transmission and distribution.

Gigawatt-Hour (GWh): One gigawatt of generation for one hour.

Green Power: Term used to describe electricity produced from environmentally friendly or renewable resources, such as solar or wind power; see "Renewable Energy."

Holding Company: A corporate structure where one company holds the stock (ownership) of one or more other companies but does not directly engage in the operation of any of its business.

Independent System Operator (ISO): An independent organization or institution that controls the transmission system in a particular region. The ISO would have no corporate relationship with the transmission-owning utilities, and therefore would be able to assure fair and comparable access to the transmission system for all users.

Kilowatt (kW): A basic unit of measurement; 1 kW = 1,000 watts.

Kilowatt-Hour (kWh): One kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Local Distribution Company (LDC): The utility that is responsible for delivering gas to the customer behind the citygate (where the pipeline delivers gas to the LDC).

Megawatt (MW): One thousand kilowatts or one million watts.

Municipal Utility: A utility that is owned and operated by a municipal government. These utilities are organized as nonprofit local government agencies and pay no taxes or dividends; they raise capital through the issuance of tax-free bonds.

North American Electric Reliability Council (NERC): A nonprofit organization formed for the purpose of coordinating electric system operation and planning throughout North America; including Mexico and Canada.

Pancaking: Occurs when a seller attempts to transmit electricity through the control areas of several utilities and must pay a separate transmission charge to each utility.

Power Exchange: An independent entity with no affiliate or financial interest in distribution, transmission or generation companies or facilities. It would match bids submitted by utilities, power marketers, brokers and other participants ranking the bids on a least-cost basis and arrange for the power to be delivered.

Power Marketers: A business entity engaged in buying and selling electricity, but does not own generation or transmission facilities. Power marketers take ownership of the electricity and offer risk management derivative products such as options, swaps, forward contracts and electricity futures.

Public Utility Holding Company Act of 1935 (PUCHA): A federal law that sought to correct abuses of utility holding companies. Holding companies largely confined to a single state or presumed to be susceptible to effective state regulation are "exempt" from federal regulation under PUHCA. Multi-state holding companies must "register" with the SEC and comply with federal regulation under PUHCA.

Public Utility Regulatory Polices Act of 1978 (PURPA): A federal law that requires utilities to buy electric power from private "qualifying facilities" at an avoided cost rate. The avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase the power itself. Utilities must further provide customers who choose to generate their own electricity a reasonably priced back-up supply of electricity.

Registered Holding Company: Any company that acquires more than 10 percent of the equity of a utility and as a consequence, must register with the Securities and Exchange Commission and is subject to all provisions of PUHCA.

Reliability: A term used in both the electric and gas industry to describe the utility's ability to provide uninterrupted service of gas or electricity. Reliability of service can be compromised at any level of service: generation or production, transmission or distribution.

Renewable Energy (Green Power): Naturally replenishable energy resources; includes geothermal, biomass, hydro-electric, solar, tidal action and wind as means of electricity generation.

Senate Enrolled Act 637: Codified as IC 8-1-2.5, this statute enables the IURC to consider alternative regulatory plans, among other things.

Service Territory: Under the current regulatory environment, an electric utility is granted a franchise to provide energy to a specified geographical territory, designated as a service territory.

Stranded Costs: Costs associated with assets that prove to be uneconomical in a competitive environment. Because these assets were previously approved by regulatory authorities and included in rates, utilities claim they should be able to fully recover these costs before the transition to customer choice is completed.

Supplier of Last Resort: In a customer choice market, the supplier of last resort will be a designated power supplier that will provide the energy needs of customer who can't or won't choose a supplier

Thirty-Day Filings: Requests for utilities for approval of new rates, changes to nonrecurring charges, altered rules and regulations or changes in periodic trackers. This process is designed to allow these types of requests to be reviewed and approved by the Commission in a more expeditious and less costly manner than a formally docketed case.

Throughput (Gas): Actual or estimated volume of natural gas that may be carried on a pipeline over a period of time.

Transition Costs: Costs resulting from restructuring an industry from a regulatory environment to a competitive environment. Stranded costs are included in transition costs but may not be the only costs incurred.

Transmission: The process of transferring energy (either gas or electricity) from the production or generation source to the point of distribution. Also refers to the facilities used for this process.

Transportation (Gas): The transportation of natural gas by a pipeline (upstream of the citygate) and/or by the LDC (behind the citygate).

Unbundling: The process of separating out the package of services offered by an electric or gas company and charging separate rates for each service that fairly represents the cost of providing the service. In the electric industry, these may include: transmission, generation, distribution services, metering, billing, maintenance. In the natural gas industry, in addition to transportation of gas, unbundling may include storage, gathering, balancing services and other items.

Universal Service: A condition that makes a utility service (gas, electricity, telephone, etc.) available to any customer that wants it, at an affordable price.

Vertically Integrated Utilities (companies): An arrangement whereby the same company owns most or all of the facilities necessary for producing, transporting and selling electricity (or gas). Traditionally, vertically integrated electric utilities have owned the generation, transmission and distribution facilities. In some cases, electric utilities have also owned coal mines and gas supplies to increase the level of vertical integration.

XI. APPENDICES

Sales, Revenue and Market Share for Indiana Electric Utilities

1997 Summary

kWh

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Investor-Owned Electric Utilities	20,360,599,000	16,435,377,000	35,633,577,000	380,249,000	72,809,802,000
Rural Electric Membership Corporations	3,801,425,465	1,665,843,939	-	36,500,716	5,503,770,120
Municipal Electric Utilities	1,656,659,318	3,695,867,853	-	108,347,193	5,460,874,364
Totals	**25,818,683,783**	**21,797,088,792**	**35,633,577,000**	**525,096,909**	**83,774,446,484**

Revenues

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Investor-Owned Electric Utilities	$1,430,097,480	$1,004,466,356	$1,487,675,849	$ 41,365,924	$3,963,605,609
Rural Electric Membership Corporations	259,194,432	87,409,330	-	2,268,144	348,871,906
Municipal Electric Utilities	91,796,732	169,082,711	-	8,109,441	268,988,884
Totals	**$1,781,088,644**	**$1,260,958,397**	**$1,487,675,849**	**$ 51,743,509**	**$4,581,466,399**

Retail Market Share by kWh

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Investor-Owned Electric Utilities	78.86%	75.40%	100.00%	72.42%	86.91%
Rural Electric Membership Corporations	14.72%	7.64%	-	6.95%	6.57%
Municipal Electric Utilities	6.42%	16.96%	-	20.63%	6.52%

Retail Market Share by Revenues

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Investor-Owned Electric Utilities	80.29%	79.66%	100.00%	79.94%	86.51%
Rural Electric Membership Corporations	14.55%	6.93%	-	4.38%	7.61%
Municipal Electric Utilities	5.15%	13.41%	-	15.67%	5.87%

Investor-Owned Electric Utilities

1997 Data

kWh

	UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
1	Indiana Michigan Power Company	5,075,191,000	4,349,146,000	7,540,355,000	82,135,000	17,046,827,000
2	Indianapolis Power & Light Company	4,254,672,000	1,959,607,000	6,833,930,000	69,542,000	13,117,751,000
3	Northern Indiana Public Service Company	2,723,990,000	2,974,703,000	8,971,926,000	142,699,000	14,813,318,000
4	PSI Energy, Inc.	7,055,370,000	5,959,701,000	10,220,011,000	64,936,000	23,300,018,000
5	Southern Indiana Gas & Electric Company	1,251,376,000	1,192,220,000	2,067,355,000	20,937,000	4,531,888,000
	Totals	20,360,599,000	16,435,377,000	35,633,577,000	380,249,000	72,809,802,000

Revenues

	UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
1	Indiana Michigan Power Company	$ 348,022,396	$ 264,030,745	$ 332,217,928	$ 6,464,623	$ 950,735,692
2	Indianapolis Power & Light Company	261,831,588	125,131,344	306,760,993	9,323,169	703,047,094
3	Northern Indiana Public Service Company	272,618,450	253,298,660	416,741,363	15,150,346	957,808,819
4	PSI Energy, Inc.	464,520,020	298,109,683	362,030,991	8,354,814	1,133,015,508
5	Southern Indiana Gas & Electric Company	83,105,026	63,895,924	69,924,574	2,072,972	218,998,496
	Totals	$ 1,430,097,480	$ 1,004,466,356	$ 1,487,675,849	$ 41,365,924	$ 3,963,605,609

Average Rate Per kWh

	UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	SYSTEM AVERAGE
1	Indiana Michigan Power Company	$0.07	$0.06	$0.04	$0.08	$0.06
2	Indianapolis Power & Light Company	0.06	0.06	0.04	0.13	0.05
3	Northern Indiana Public Service Company	0.10	0.09	0.05	0.11	0.06
4	PSI Energy, Inc.	0.07	0.05	0.04	0.13	0.05
5	Southern Indiana Gas & Electric Company	0.07	0.05	0.03	0.10	0.05

Retail Market Share by Revenues

	UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	
1	Indiana Michigan Power Company	36.61%	27.77%	34.94%	0.68%	
2	Indianapolis Power & Light Company	37.24%	17.80%	43.63%	1.33%	
3	Northern Indiana Public Service Company	28.46%	26.45%	43.51%	1.58%	
4	PSI Energy, Inc.	41.00%	26.31%	31.95%	0.74%	
5	Southern Indiana Gas & Electric Company	37.95%	29.18%	31.93%	0.95%	

Rural Electric Membership Corporations

1997 Data

kWh

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Bartholomew County R.E.M.C.	123,125,967	112,336,089	791,407	236,253,463
2.	Central Indiana Power	117,797,352	18,400,257	157,022	136,354,631
3.	Decatur County R.E.M.C.	86,320,692	147,956,373	127,155	234,404,220
4.	Dubois R.E.C., Inc.	130,177,009	70,040,970	968,449	201,186,428
5.	Fulton County R.E.M.C.	60,191,915	12,114,233	2,659,086	74,965,234
6.	Harrison County R.E.M.C.	249,893,955	116,039,722	1,895,050	367,828,727
7.	Hendricks County R.E.M.C.	251,881,694	40,884,465	4,896,207	297,662,366
8.	Henry County R.E.M.C.	119,449,049	25,102,728	2,640,464	147,192,241
9.	Jackson County R.E.M.C.	303,201,953	60,985,248	56,199	364,243,400
10.	Jay County R.E.M.C.	75,642,736	16,674,300	-	92,317,036
11.	Johnson County R.E.M.C.	164,858,958	62,560,997	280,418	227,700,373
12.	Kankakee Valley R.E.M.C.	140,429,599	45,117,544	-	185,547,143
13.	Kosciusko County R.E.M.C.	144,396,988	99,815,575	758,816	244,971,379
14.	Marshall County R.E.M.C.	58,634,952	13,441,469	602,410	72,678,831
15.	Miami-Cass County R.E.M.C.	65,687,704	27,502,646	14,693,744	107,884,094
16.	Newton County R.E.M.C.	14,952,409	8,388,256	248,221	23,588,886
17.	Northeastern R.E.M.C.	228,630,292	180,635,675	699,596	409,965,563
18.	Orange County R.E.M.C.	75,175,733	10,227,312	929,697	86,332,742
19.	South Central Indiana R.E.M.C.	356,989,801	44,835,922	-	401,825,723
20.	Southeastern Indiana R.E.M.C.	290,837,779	50,766,982	-	341,604,761
21.	Steuben County R.E.M.C.	62,520,532	32,128,945	695,524	95,345,001
22.	Tipmont R.E.M.C.	202,314,220	68,206,505	2,381,009	272,901,734
23.	United R.E.M.C.	140,077,557	262,712,451	-	402,790,008
24.	Utilities District of Western Indiana R.E.M.C.	196,534,227	54,220,539	-	250,754,766
25.	Wabash County R.E.M.C.	71,217,559	55,236,031	1,020,242	127,473,832
26.	White County R.E.M.C.	70,484,833	29,512,705	-	99,997,538
	Totals	3,801,425,465	1,665,843,939	36,500,716	5,503,770,120

Rural Electric Membership Corporations
1997 Data

Revenues

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Bartholomew County R.E.M.C.	$ 8,420,457	$ 6,260,701	$ 54,875	$ 14,736,033
2.	Central Indiana Power	8,155,873	1,291,287	10,263	9,457,423
3.	Decatur County R.E.M.C.	5,738,474	5,958,258	10,412	11,707,144
4.	Dubois R.E.C., Inc.	8,099,785	3,767,478	65,028	11,932,291
5.	Fulton County R.E.M.C.	4,190,035	821,591	198,434	5,210,060
6.	Harrison County R.E.M.C.	15,772,782	5,417,206	138,178	21,328,166
7.	Hendricks County R.E.M.C.	17,330,713	2,270,162	394,911	19,995,786
8.	Henry County R.E.M.C.	6,748,546	1,576,751	192,518	8,517,815
9.	Jackson County R.E.M.C.	19,202,362	3,600,493	8,523	22,811,378
10.	Jay County R.E.M.C.	5,305,762	1,110,948	-	6,416,710
11.	Johnson County R.E.M.C.	12,107,103	3,579,624	64,118	15,750,845
12.	Kankakee Valley R.E.M.C.	10,265,267	3,091,387	-	13,356,654
13.	Kosciusko County R.E.M.C.	8,961,930	5,213,692	55,670	14,231,292
14.	Marshall County R.E.M.C.	4,987,293	971,502	67,118	6,025,913
15.	Miami-Cass County R.E.M.C.	4,502,661	1,510,892	535,676	6,549,229
16.	Newton County R.E.M.C.	1,102,578	538,049	17,086	1,657,713
17.	Northeastern R.E.M.C.	15,517,317	9,699,817	42,140	25,259,274
18.	Orange County R.E.M.C.	5,725,810	868,192	74,651	6,668,653
19.	South Central Indiana R.E.M.C.	25,682,865	2,207,203	-	27,890,068
20.	Southeastern Indiana R.E.M.C.	20,341,851	3,053,884	-	23,395,735
21.	Steuben County R.E.M.C.	4,590,896	1,888,632	51,766	6,531,294
22.	Tipmont R.E.M.C.	14,296,413	4,013,360	177,381	18,487,154
23.	United R.E.M.C.	8,912,386	10,949,255	-	19,861,641
24.	Utilities District of Western Indiana R.E.M.C.	13,018,435	3,080,395	-	16,098,830
25.	Wabash County R.E.M.C.	4,935,907	2,968,179	109,396	8,013,482
26.	White County R.E.M.C.	5,280,931	1,700,392	-	6,981,323
	Totals	$ 259,194,432	$ 87,409,330	$ 2,268,144	$ 348,871,906

Rural Electric Membership Corporations

1997 Data

Average Rate Per kWh

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	SYSTEM AVERAGE
1.	Bartholomew County R.E.M.C.	$0.07	$0.06	$0.07	$0.06
2.	Central Indiana Power	0.07	0.07	0.07	0.07
3.	Decatur County R.E.M.C.	0.07	0.04	0.08	0.05
4.	Dubois R.E.C., Inc.	0.06	0.05	0.07	0.06
5.	Fulton County R.E.M.C.	0.07	0.07	0.07	0.07
6.	Harrison County R.E.M.C.	0.06	0.05	0.07	0.06
7.	Hendricks County R.E.M.C.	0.07	0.06	0.08	0.07
8.	Henry County R.E.M.C.	0.06	0.06	0.07	0.06
9.	Jackson County R.E.M.C.	0.06	0.06	0.15	0.06
10.	Jay County R.E.M.C.	0.07	0.07	-	0.07
11.	Johnson County R.E.M.C.	0.07	0.06	0.23	0.07
12.	Kankakee Valley R.E.M.C.	0.07	0.07	-	0.07
13.	Kosciusko County R.E.M.C.	0.06	0.05	0.07	0.06
14.	Marshall County R.E.M.C.	0.09	0.07	0.11	0.08
15.	Miami-Cass County R.E.M.C.	0.07	0.05	0.04	0.06
16.	Newton County R.E.M.C.	0.07	0.06	0.07	0.07
17.	Northeastern R.E.M.C.	0.07	0.05	0.06	0.06
18.	Orange County R.E.M.C.	0.08	0.08	0.08	0.08
19.	South Central Indiana R.E.M.C.	0.07	0.05	-	0.07
20.	Southeastern Indiana R.E.M.C.	0.07	0.06	-	0.07
21.	Steuben County R.E.M.C.	0.07	0.06	0.07	0.07
22.	Tipmont R.E.M.C.	0.07	0.06	0.07	0.07
23.	United R.E.M.C.	0.06	0.04	-	0.05
24.	Utilities District of Western Indiana R.E.M.C.	0.07	0.06	-	0.06
25.	Wabash County R.E.M.C.	0.07	0.05	0.11	0.06
26.	White County R.E.M.C.	0.07	0.06	-	0.07

Rural Electric Membership Corporations
1997 Data

Retail Market Share

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER
1.	Bartholomew County R.E.M.C.	57.14%	42.49%	0.37%
2.	Central Indiana Power	86.24%	13.65%	0.11%
3.	Decatur County R.E.M.C.	49.02%	50.89%	0.09%
4.	Dubois R.E.C., Inc.	67.88%	31.57%	0.54%
5.	Fulton County R.E.M.C.	80.42%	15.77%	3.81%
6.	Harrison County R.E.M.C.	73.95%	25.40%	0.65%
7.	Hendricks County R.E.M.C.	86.67%	11.35%	1.97%
8.	Henry County R.E.M.C.	79.23%	18.51%	2.26%
9.	Jackson County R.E.M.C.	84.18%	15.78%	0.04%
10.	Jay County R.E.M.C.	82.69%	17.31%	-
11.	Johnson County R.E.M.C.	76.87%	22.73%	0.41%
12.	Kankakee Valley R.E.M.C.	76.86%	23.14%	-
13.	Kosciusko County R.E.M.C.	62.97%	36.64%	0.39%
14.	Marshall County R.E.M.C.	82.76%	16.12%	1.11%
15.	Miami-Cass County R.E.M.C.	68.75%	23.07%	8.18%
16.	Newton County R.E.M.C.	66.51%	32.46%	1.03%
17.	Northeastern R.E.M.C.	61.43%	38.40%	0.17%
18.	Orange County R.E.M.C.	85.86%	13.02%	1.12%
19.	South Central Indiana R.E.M.C.	92.09%	7.91%	-
20.	Southeastern Indiana R.E.M.C.	86.95%	13.05%	-
21.	Steuben County R.E.M.C.	70.29%	28.92%	0.79%
22.	Tipmont R.E.M.C.	77.33%	21.71%	0.96%
23.	United R.E.M.C.	44.87%	55.13%	-
24.	Utilities District of Western Indiana R.E.M.C.	80.87%	19.13%	-
25.	Wabash County R.E.M.C.	61.60%	37.04%	1.37%
26.	White County R.E.M.C.	75.64%	24.36%	-

Municipal Electric Utilities
1997 Data
kWh

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Anderson Municipal Light & Power	289,696,498	379,412,299	4,832,736	673,941,533
2.	Auburn Municipal Electric	49,145,768	459,400,676	-	508,546,444
3.	Bargersville Municipal Power & Light	23,372,726	15,479,985	1,370,292	40,223,003
4.	Bluffton Municipal Electric	40,810,280	134,754,768	4,806,226	180,371,274
5.	Boonville Municipal Light & Power	29,396,427	32,893,767	-	62,290,194
6.	Cannelton Municipal Electric	6,514,350	12,383,595	410,320	19,308,265
7.	Centerville Municipal Power & Light	14,820,345	5,687,815	1,533,620	22,041,780
8.	Columbia City Municipal Electric	31,733,303	66,527,567	1,265,307	99,526,177
9.	Covington Municipal Electric	12,070,242	10,568,120	-	22,638,362
10.	Crawfordsville Municipal Electric Light & Power	69,901,894	311,454,469	12,101,446	393,457,809
11.	Edinburgh Municipal Electric	20,629,911	65,516,530	-	86,146,441
12.	Flora Municipal Electric	10,647,080	10,088,917	497,700	21,233,697
13.	Frankfort City Light & Power	67,575,282	257,996,439	2,619,991	328,191,712
14.	Greenfield Municipal Electric	48,294,966	151,556,710	2,688,306	202,539,982
15.	Kingsford Heights Municipal Electric	4,613,810	-	-	4,613,810
16.	Knightstown Municipal Electric	12,004,289	8,293,564	639,712	20,937,565
17.	Lawrenceburg Municipal Electric	23,374,705	58,951,925	983,742	83,310,372
18.	Lebanon Municipal Electric	54,763,291	89,123,919	2,703,277	146,590,487
19.	Logansport Municipal Electric	88,583,547	251,141,253	2,626,858	342,351,658
20.	Mishawaka Municipal Electric	154,935,990	327,100,137	20,982,570	503,018,697
21.	Peru Municipal Electric Light & Power	83,029,130	123,501,886	5,155,843	211,686,859
22.	Richmond Municipal Power & Light	185,509,002	693,836,303	10,799,444	890,144,749
23.	Scottsburg Municipal Electric	178,399,690	-	-	178,399,690
24.	South Whitley Municipal Electric	19,377,749	-	-	19,377,749
25.	Straughn Municipal Electric	1,315,090	-	-	1,315,090
26.	Tell City Municipal Electric	31,135,310	81,258,889	22,093,728	134,487,927
27.	Tipton Municipal Electric	32,049,089	61,422,432	1,014,422	94,485,943
28.	Troy Municipal Electric	10,495,457	-	-	10,495,457
29.	Washington City Municipal Light & Power	62,464,097	87,515,888	9,221,653	159,201,638
	Totals	**1,656,659,318**	**3,695,867,853**	**108,347,193**	**5,460,874,364**

Municipal Electric Utilities
1997 Data
Revenues

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Anderson Municipal Light & Power	$ 15,950,611	$ 17,937,279	$ 291,898	$ 34,179,788
2.	Auburn Municipal Electric	2,239,294	19,494,176	-	21,733,470
3.	Bargersville Municipal Power & Light	1,370,599	1,018,037	90,390	2,479,026
4.	Bluffton Municipal Electric	2,237,795	6,343,807	263,086	8,844,688
5.	Boonville Municipal Light & Power	1,931,753	2,054,506	-	3,986,259
6.	Cannelton Municipal Electric	490,527	833,388	18,271	1,342,186
7.	Centerville Municipal Power & Light	599,101	362,380	65,778	1,027,259
8.	Columbia City Municipal Electric	1,776,851	3,568,006	79,607	5,424,464
9.	Covington Municipal Electric	733,578	614,017	-	1,347,595
10.	Crawfordsville Municipal Electric Light & Power	4,185,232	12,656,162	2,228,857	19,070,251
11.	Edinburgh Municipal Electric	1,103,877	3,042,374	-	4,146,251
12.	Flora Municipal Electric	566,646	524,316	29,151	1,120,113
13.	Frankfort City Light & Power	3,757,041	10,182,972	206,013	14,146,026
14.	Greenfield Municipal Electric	2,578,699	6,494,884	234,517	9,308,100
15.	Kingsford Heights Municipal Electric	368,410	-	-	368,410
16.	Knightstown Municipal Electric	625,513	442,800	31,810	1,100,123
17.	Lawrenceburg Municipal Electric	1,224,673	2,949,633	28,248	4,202,554
18.	Lebanon Municipal Electric	3,120,077	4,250,041	117,780	7,487,898
19.	Logansport Municipal Electric	5,790,063	12,918,060	126,840	18,834,963
20.	Mishawaka Municipal Electric	9,939,667	18,293,534	1,490,663	29,723,864
21.	Peru Municipal Electric Light & Power	4,443,718	5,137,584	240,048	9,821,350
22.	Richmond Municipal Power & Light	10,328,601	29,093,900	855,430	40,277,931
23.	Scottsburg Municipal Electric	7,578,577	-	-	7,578,577
24.	South Whitley Municipal Electric	1,006,591	-	-	1,006,591
25.	Straughn Municipal Electric	83,984	-	-	83,984
26.	Tell City Municipal Electric	2,090,667	4,329,147	1,189,017	7,608,831
27.	Tipton Municipal Electric	1,712,288	2,832,800	71,213	4,616,301
28.	Troy Municipal Electric	713,825	-	-	713,825
29.	Washington City Municipal Light & Power	3,248,474	3,708,908	450,824	7,408,206
	Totals	$91,796,732	$169,082,711	$8,109,441	$268,988,884

Municipal Electric Utilities
1997 Data
Average Rate Per kWh

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	SYSTEM AVERAGE
1.	Anderson Municipal Light & Power	$0.06	$0.05	$0.06	$0.05
2.	Auburn Municipal Electric	0.05	0.04	-	0.04
3.	Bargersville Municipal Power & Light	0.06	0.07	0.07	0.06
4.	Bluffton Municipal Electric	0.05	0.05	0.05	0.05
5.	Boonville Municipal Light & Power	0.07	0.06	-	0.06
6.	Cannelton Municipal Electric	0.08	0.07	0.04	0.07
7.	Centerville Municipal Power & Light	0.04	0.06	0.04	0.05
8.	Columbia City Municipal Electric	0.06	0.05	0.06	0.05
9.	Covington Municipal Electric	0.06	0.06	-	0.06
10.	Crawfordsville Municipal Electric Light & Power	0.06	0.04	0.18	0.05
11.	Edinburgh Municipal Electric	0.05	0.05	-	0.05
12.	Flora Municipal Electric	0.05	0.05	0.06	0.05
13.	Frankfort City Light & Power	0.06	0.04	0.08	0.04
14.	Greenfield Municipal Electric	0.05	0.04	0.09	0.05
15.	Kingsford Heights Municipal Electric	0.08	-	-	0.08
16.	Knightstown Municipal Electric	0.05	0.05	0.05	0.05
17.	Lawrenceburg Municipal Electric	0.05	0.05	0.03	0.05
18.	Lebanon Municipal Electric	0.06	0.05	0.04	0.05
19.	Logansport Municipal Electric	0.07	0.05	0.05	0.06
20.	Mishawaka Municipal Electric	0.06	0.06	0.07	0.06
21.	Peru Municipal Electric Light & Power	0.05	0.04	0.05	0.05
22.	Richmond Municipal Power & Light	0.06	0.04	0.08	0.05
23.	Scottsburg Municipal Electric	0.04	-	-	0.04
24.	South Whitley Municipal Electric	0.05	-	-	0.05
25.	Straughn Municipal Electric	0.06	-	-	0.06
26.	Tell City Municipal Electric	0.07	0.05	0.05	0.06
27.	Tipton Municipal Electric	0.05	0.05	0.07	0.05
28.	Troy Municipal Electric	0.07	-	-	0.07
29.	Washington City Municipal Light & Power	0.05	0.04	0.05	0.05

Municipal Electric Utilities
1997 Data
Retail Market Share

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER
1.	Anderson Municipal Light & Power	46.67%	52.48%	0.85%
2.	Auburn Municipal Electric	10.30%	89.70%	-
3.	Bargersville Municipal Power & Light	55.29%	41.07%	3.65%
4.	Bluffton Municipal Electric	25.30%	71.72%	2.97%
5.	Boonville Municipal Light & Power	48.46%	51.54%	-
6.	Cannelton Municipal Electric	36.55%	62.09%	1.36%
7.	Centerville Municipal Power & Light	58.32%	35.28%	6.40%
8.	Columbia City Municipal Electric	32.76%	65.78%	1.47%
9.	Covington Municipal Electric	54.44%	45.56%	-
10.	Crawfordsville Municipal Electric Light & Power	21.95%	66.37%	11.69%
11.	Edinburgh Municipal Electric	26.62%	73.38%	-
12.	Flora Municipal Electric	50.59%	46.81%	2.60%
13.	Frankfort City Light & Power	26.56%	71.98%	1.46%
14.	Greenfield Municipal Electric	27.70%	69.78%	2.52%
15.	Kingsford Heights Municipal Electric	100.00%	-	-
16.	Knightstown Municipal Electric	56.86%	40.25%	2.89%
17.	Lawrenceburg Municipal Electric	29.14%	70.19%	0.67%
18.	Lebanon Municipal Electric	41.67%	56.76%	1.57%
19.	Logansport Municipal Electric	30.74%	68.59%	0.67%
20.	Mishawaka Municipal Electric	33.44%	61.54%	5.02%
21.	Peru Municipal Electric Light & Power	45.25%	52.31%	2.44%
22.	Richmond Municipal Power & Light	25.64%	72.23%	2.12%
23.	Scottsburg Municipal Electric	100.00%	-	-
24.	South Whitley Municipal Electric	100.00%	-	-
25.	Straughn Municipal Electric	100.00%	-	-
26.	Tell City Municipal Electric	27.48%	56.90%	15.63%
27.	Tipton Municipal Electric	37.09%	61.37%	1.54%
28.	Troy Municipal Electric	100.00%	-	-
29.	Washington City Municipal Light & Power	43.85%	50.06%	6.09%

ANALYSIS OF GAS SALES DATA
FOR 1995, 1996, AND 1997

CITIZENS GAS AND COKE UTILITY	1997	1996	1995
Revenues By Customer Class			
Residential	$ 160,695,010	$ 158,540,640	$ 130,820,976
Commercial & Industrial	96,813,518	101,111,142	58,071,813
Other	3,019,648	11,226,656	28,540,172
Totals	$ 260,528,176	$ 270,878,438	$ 217,432,961
Sales By Customer Class in Dth			
Residential	26,392,624	28,483,330	25,157,784
Commercial & Industrial	21,857,492	25,355,484	14,708,759
Other	374,100	2,939,050	15,268,936
Totals	48,624,216	56,777,864	55,135,479
Revenues Per Dth			
Residential	$ 6.0886	$ 5.5661	$ 5.2000
Commercial & Industrial	$ 4.4293	$ 3.9877	$ 3.9481
Other	$ 8.0718	$ 3.8198	$ 1.8692
Average Rate	$ 5.3580	$ 4.7708	$ 3.9436

INDIANA GAS COMPANY, INC.	1997	1996	1995
Revenues By Customer Class			
Residential	$ 335,787,421	$ 318,688,359	$ 242,626,142
Commercial & Industrial	172,341,621	188,768,380	142,383,751
Other	-	-	-
Totals	$ 508,129,042	$ 507,456,739	$ 385,009,893
Sales By Customer Class in Dth			
Residential	48,208,746	48,866,563	45,603,294
Commercial & Industrial	32,934,928	40,083,883	38,959,969
Other	-	-	-
Totals	81,143,674	88,950,446	84,563,263
Revenues Per Dth			
Residential	$ 6.9653	$ 6.5216	$ 5.3204
Commercial & Industrial	$ 5.2328	$ 4.7093	$ 3.6546
Other	$ -	$ -	$ -
Average Rate	$ 6.2621	$ 5.7049	$ 4.5529

ANALYSIS OF GAS SALES DATA
FOR 1995, 1996, AND 1997

NORTHERN INDIANA PUBLIC SERVICE CO.	1997	1996	1995
Revenues By Customer Class			
Residential	$ 700,657,091	$ 385,222,725	$ 373,114,019
Commercial & Industrial		218,050,592	179,587,768
Other	34,641,968	25,463,383	2,467,242
Totals	$ 735,299,059	$ 628,736,700	$ 555,169,029
Sales By Customer Class in Dth			
Residential	73,452,000	77,050,000	71,112,702
Commercial & Industrial	44,857,000	45,929,000	42,086,250
Other	13,887,000	7,922,000	941,291
Totals	132,196,000	130,901,000	114,140,243
Revenues Per Dth			
Residential	$ 9.5390	$ 4.9996	$ 5.2468
Commercial & Industrial	$ -	$ 4.7476	$ 4.2671
Other	$ 2.4946	$ 3.2143	$ 2.6211
Average Rate	$ 5.5622	$ 4.8031	$ 4.8639

SOUTHERN INDIANA GAS & ELECTRIC CO.	1997	1996	1995
Revenues By Customer Class			
Residential	55,679,900	$ 45,525,451	$ 38,692,723
Commercial & Industrial	25,480,297	26,665,542	18,999,762
Other	2,663,430	5,193,441	247,401
Totals	$ 83,823,627	$ 77,384,434	$ 57,939,886
Sales By Customer Class in Dth			
Residential	9,653,802	10,435,599	8,925,434
Commercial & Industrial	5,366,554	7,842,415	6,169,749
Other	(194,892)	985,306	85,133
Totals	14,825,464	19,263,320	15,180,316
Revenues Per Dth			
Residential	$ 5.7677	$ 4.3625	$ 4.3351
Commercial & Industrial	$ 4.7480	$ 3.4002	$ 3.0795
Other	$ (13.6662)	$ 5.2709	$ 2.9061
Average Rate	$ 5.6540	$ 4.0172	$ 3.8168

CITIZENS GAS AND COKE UTILITY
ANALYSIS OF GAS SALES DATA

	1997	1996	1995	1994	1993	1992	1991	1990	1989	1988
Total Sales By Class (Dth)										
Residential	26,392,624	28,483,330	25,157,784	25,786,208	26,338,840	24,288,992	24,139,468	23,270,985	25,551,980	24,904,564
Commercial	14,934,080	17,041,493	12,349,373	11,653,505	13,161,441	12,958,457	11,199,869	12,006,600	12,693,703	11,602,486
Industrial	6,923,412	8,313,991	2,359,386	2,054,039	4,550,216	5,784,674	2,055,701	3,096,836	3,307,359	2,648,699
Other	374,100	2,939,050	15,268,936	3,825,713	-	-	-	-	-	-
Total	48,624,216	56,777,864	55,135,479	43,319,465	44,050,497	43,032,123	37,395,038	38,374,421	41,553,042	39,155,749
Total Transportation By Class (Dth)										
Residential	-	-	-	-	-	-	-	-	-	-
Commercial	2,168,530	929,276	4,011,118	3,967,667	2,854,679	1,528,888	2,921,525	1,532,351	2,076,425	2,243,491
Industrial	6,976,993	5,084,490	9,543,189	9,086,966	6,407,740	4,246,554	7,351,172	6,119,584	6,371,800	6,761,870
Other	-	163,656	-	-	-	-	-	-	-	-
Total	9,145,523	6,177,422	13,554,307	13,054,633	9,262,419	5,775,442	10,272,697	7,651,935	8,448,225	9,005,361
Total Throughput By Class (Dth)										
Residential	26,392,624	28,483,330	25,157,784	25,786,208	26,338,840	24,288,992	24,139,468	23,270,985	25,551,980	24,904,564
Commercial	17,102,610	17,970,769	16,360,491	15,621,172	16,016,120	14,487,345	14,121,394	13,538,951	14,770,128	13,845,977
Industrial	13,900,405	13,398,481	11,902,575	11,141,005	10,957,956	10,031,228	9,406,873	9,216,420	9,679,159	9,410,569
Other	374,100	3,193,406	15,268,936	3,825,713	-	-	-	-	-	-
Total	57,769,739	63,045,986	68,689,786	56,374,098	53,312,916	48,807,565	47,667,735	46,026,356	50,001,267	48,161,110
Percent Transportation to Throughput										
Residential	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Commercial	12.68%	5.17%	24.52%	25.40%	17.82%	10.55%	20.69%	11.32%	14.06%	16.20%
Industrial	50.19%	37.95%	80.18%	81.56%	58.48%	42.33%	78.15%	66.40%	65.83%	71.85%
Other	0.00%	5.12%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	15.83%	9.80%	19.73%	23.16%	17.37%	11.83%	21.55%	16.63%	16.90%	18.70%

INDIANA GAS COMPANY, INC.
ANALYSIS OF GAS SALES DATA

	1997	1996	1995	1994	1993	1992	1991	1990	1989	1988
Total Sales By Class (Dth)										
Residential	48,208,746	48,866,563	45,603,294	46,634,000	44,690,000	41,065,000	38,996,000	36,194,000	35,976,000	34,173,000
Commercial	19,435,857	19,778,149	18,082,023	18,258,000	17,613,000	15,711,000	15,225,000	13,960,000	13,707,000	12,916,000
Industrial	13,499,071	20,305,734	20,877,946	21,268,000	36,744,000	31,771,000	24,928,000	19,038,000	13,695,000	13,254,000
Other	-	-	-	-	-	-	-	-	-	-
Total	81,143,674	88,950,446	84,563,263	86,160,000	99,047,000	88,547,000	79,149,000	69,192,000	63,378,000	60,343,000
Total Transportation By Class (Dth)										
Residential	-	-	-	-	-	-	-	-	-	-
Commercial	-	-	-	-	-	-	-	-	-	-
Industrial	42,778,546	36,048,401	33,916,075	30,125,000	12,307,000	13,438,000	18,354,000	21,027,000	23,427,000	22,000,000
Other	-	-	-	-	-	-	-	-	-	-
Total	42,778,546	36,048,401	33,916,075	30,125,000	12,307,000	13,438,000	18,354,000	21,027,000	23,427,000	22,000,000
Total Throughput By Class (Dth)										
Residential	48,208,746	48,866,563	45,603,294	46,634,000	44,690,000	41,065,000	38,996,000	36,194,000	35,976,000	34,173,000
Commercial	19,435,857	19,778,149	18,082,023	18,258,000	17,613,000	15,711,000	15,225,000	13,960,000	13,707,000	12,916,000
Industrial	56,277,617	56,354,135	54,794,021	51,393,000	49,051,000	45,209,000	43,282,000	40,065,000	37,122,000	35,254,000
Other	-	-	-	-	-	-	-	-	-	-
Total	123,922,220	124,998,847	118,479,338	116,285,000	111,354,000	101,985,000	97,503,000	90,219,000	86,805,000	82,343,000
Percent Transportation to Throughput										
Residential	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Commercial	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Industrial	76.01%	63.97%	61.90%	58.62%	25.09%	29.72%	42.41%	52.48%	63.11%	62.40%
Other	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	34.52%	28.84%	28.63%	25.91%	11.05%	13.18%	18.82%	23.31%	26.99%	26.72%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ANALYSIS OF GAS SALES DATA

	1997	1996	1995	1994	1993	1992	1991	1990	1989	1988
Total Sales By Class (Dth)										
Residential	73,452,000	77,050,000	71,113,000	67,665,000	70,707,000	67,742,000	64,159,000	61,484,000	65,586,000	69,179,000
Commercial	29,050,000	29,401,000	26,908,000	25,994,000	27,466,000	26,191,000	24,051,000	24,286,000	26,446,000	26,777,000
Industrial	15,807,000	16,528,000	15,178,000	14,638,000	13,567,000	15,278,000	18,907,000	21,273,000	27,310,000	31,241,000
Other	13,887,000	7,922,000	941,000	357,000	450,000	493,000	484,000	470,000	551,000	654,000
Total	132,196,000	130,901,000	114,140,000	108,654,000	112,190,000	109,704,000	107,601,000	107,513,000	119,893,000	127,851,000
Total Transportation By Class (Dth)										
Residential	-	-	-	-	-	-	-	-	-	-
Commercial	3,957,000	3,740,000	3,855,000	4,330,000	-	-	-	-	-	-
Industrial	156,484,000	151,446,000	157,849,000	160,232,000	162,853,000	147,818,000	135,921,000	133,950,000	126,013,000	123,796,000
Other	-	-	-	-	-	-	-	-	-	-
Total	160,441,000	155,186,000	161,704,000	164,562,000	162,853,000	147,818,000	135,921,000	133,950,000	126,013,000	123,796,000
Total Throughput By Class (Dth)										
Residential	73,452,000	77,050,000	71,113,000	67,665,000	70,707,000	67,742,000	64,159,000	61,484,000	69,586,000	69,179,000
Commercial	33,007,000	33,141,000	30,763,000	30,324,000	27,466,000	26,191,000	24,051,000	24,286,000	26,446,000	26,777,000
Industrial	172,291,000	167,974,000	173,027,000	174,870,000	176,420,000	163,096,000	154,828,000	155,223,000	153,323,000	155,037,000
Other	13,887,000	7,922,000	941,000	357,000	450,000	493,000	484,000	470,000	551,000	654,000
Total	292,637,000	286,087,000	275,844,000	273,216,000	275,043,000	257,522,000	243,522,000	241,463,000	249,906,000	251,647,000
Percent Transportation to Throughput										
Residential	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Commercial	11.99%	11.29%	12.53%	14.28%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Industrial	90.83%	90.16%	91.23%	91.63%	92.31%	90.63%	87.79%	86.30%	82.19%	79.85%
Other	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	54.83%	54.24%	58.62%	60.23%	59.21%	57.40%	55.81%	55.47%	50.42%	49.19%

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
ANALYSIS OF GAS SALES DATA

	1997	1996	1995	1994	1993	1992	1991	1990	1989	1988
Total Sales By Class (Dth)										
Residential	9,653,802	10,435,599	8,947,330	9,419,367	9,880,924	8,774,852	8,746,747	8,502,944	8,869,774	8,772,000
Commercial	4,367,755	5,174,821	4,240,884	4,177,139	4,389,045	3,986,459	3,867,513	3,696,761	3,815,649	3,722,000
Industrial	998,799	2,667,594	1,810,903	1,628,831	2,402,969	3,170,595	2,504,050	2,139,499	1,989,033	2,128,000
Other	(194,892)	985,306	387,167	165,229	150,332	20,736	21,578	22,633	27,824	30,000
Total	14,825,464	19,263,320	15,386,284	15,390,566	16,823,270	15,952,642	15,139,888	14,361,837	14,702,280	14,652,000
Total Transportation By Class (Dth)										
Residential	-	-	-	-	-	-	-	-	-	-
Commercial	781,909	268,144	277,923	293,439	238,154	89,482	190,602	231,680	Information not available	
Industrial	12,989,812	11,049,737	10,964,904	10,946,277	10,938,554	9,229,065	9,115,763	9,851,104	Information not available	
Other	772,338	483,495	720,704	344,822	193,834	184,608	178,900	193,579	Information not available	
Total	14,544,059	11,801,376	11,963,531	11,584,538	11,370,542	9,503,155	9,485,265	10,276,363	10,443,052	9,754,000
Total Throughput By Class (Dth)										
Residential	9,653,802	10,435,599	8,947,330	9,419,367	9,880,924	8,774,852	8,746,747	8,502,944	8,869,774	8,772,000
Commercial	5,149,664	5,442,965	4,518,807	4,470,578	4,627,199	4,075,941	4,058,115	3,928,441	Information not available	
Industrial	13,988,611	13,717,331	12,775,807	12,575,108	13,341,523	12,399,660	11,619,813	11,990,603	Information not available	
Other	577,446	1,468,801	1,107,871	510,051	344,166	205,344	200,478	216,212	Information not available	
Total	29,369,523	31,064,696	27,349,815	26,975,104	28,193,812	25,455,797	24,625,153	24,638,200	25,145,332	24,406,000
Percent Transportation to Throughput										
Residential	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Commercial	15.18%	4.93%	6.15%	6.56%	5.15%	2.20%	4.70%	5.90%	Information not available	
Industrial	92.86%	80.55%	85.83%	87.05%	81.99%	74.43%	78.45%	82.16%	Information not available	
Other	133.75%	32.92%	65.05%	67.61%	56.32%	89.90%	89.24%	89.53%	Information not available	
Total	49.52%	37.99%	43.74%	42.95%	40.33%	37.33%	38.52%	41.71%	41.53%	39.97%

CITIZENS GAS, INDIANA GAS, NIPSCO AND SIGECO COMBINED
ANALYSIS OF GAS SALES DATA

	1997	1996	1995	1994	1993	1992	1991	1990	1989	1988
Total Sales By Class (1,000 Dth)										
Residential	157,707	164,835	150,821	149,505	151,617	141,871	136,041	129,452	135,984	137,029
Commercial	67,788	71,395	61,580	60,083	62,629	58,847	54,343	53,949	56,662	55,017
Industrial	37,228	47,815	40,226	39,589	57,264	56,004	48,395	45,547	46,301	49,272
Other	14,066	11,846	16,597	4,348	600	514	506	493	579	684
Total	276,789	295,893	269,225	253,524	272,111	257,236	239,285	229,441	239,526	242,002
Total Transportation By Class (1,000 Dth)										
Residential	-	-	-	-	-	-	-	-	-	-
Commercial	6,907	4,937	8,144	8,591	3,093	1,618	3,112	1,764	Information not available	
Industrial	219,229	203,629	212,273	210,390	192,506	174,732	170,742	170,948	Information not available	
Other	772	647	721	345	194	185	179	194	Information not available	
Total	226,909	209,213	221,138	219,326	195,793	176,535	174,033	172,905	168,331	164,555
Total Throughput By Class (1,000 Dth)										
Residential	157,707	164,835	150,821	149,505	151,617	141,871	136,041	129,452	135,984	137,029
Commercial	74,695	76,333	69,724	68,674	65,722	60,465	57,456	55,713	Information not available	
Industrial	256,458	251,444	252,499	249,979	249,770	230,736	219,137	216,495	Information not available	
Other	14,839	12,584	17,318	4,693	794	698	684	686	Information not available	
Total	503,698	505,197	490,363	472,850	467,904	433,770	413,318	402,347	411,858	406,557
Percent Transportation to Throughput										
Residential	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Commercial	9.25%	6.47%	11.68%	12.51%	4.71%	2.68%	5.42%	3.17%	Information not available	
Industrial	85.48%	80.98%	84.07%	84.16%	77.07%	75.73%	77.92%	78.96%	Information not available	
Other	5.20%	5.14%	4.16%	7.35%	24.41%	26.44%	26.14%	28.21%	Information not available	
Total	45.05%	41.41%	45.10%	46.38%	41.84%	40.70%	42.11%	42.97%	40.87%	40.48%

ELECTRIC RESTRUCTURING ACTIVITIES BY STATE

ALABAMA- There has been no restructuring activity in Alabama since 1996 when the Senate approved a bill (H.B. 350) that gave the state regulatory authorities power to review new power contracts signed by customers who leave their utility system and order payment of stranded costs.

ALASKA - Due to is geographical location, the Alaska Commission was not contacted.

ARIZONA - The Arizona Corporation Commission voted to require Arizona's investor-owned electric utilities to sell their generating stations if they expect 100% stranded cost recovery under the ACC's competitive market plan. Under the divestiture plan, however, IOUs can keep 50% of the amount over book value they receive for their generating plants.

If the IOUs decline to divest, they have the option of using a "transition revenue methodology" to recover stranded cost, but 100% recovery is not guaranteed. Details of the revenue transition methodology are not yet set. The ACC estimates current stranded cost in Arizona are about $2-billion. The utilities have never submitted figures.

Other parts of the plan are crafted to cut residential power rates up to 5% over the next two years; launch a retail residential pilot program, and; allow large users to shop for alternative supplies. Under the ACC's plan, 20% of IOU customers - the largest users - could select their electric company starting January 1, 1999, with remaining customers given the same option no later than January 1, 2001. End-users of between 20-kW and 1 MW could aggregate use to get to the 1 MW threshold, and would then be able to seek alternative suppliers.

The ACC may have resolved the stranded cost issue for Arizona's competitive power market but it must still resolve any conflict between its plan and the competition bill recently passed by the Arizona Legislature (HB 2663). That measure applies only to publicly-owned entities, such as Salt River Project.

A key conflict between the ACC plan and HB 2663 is that HB 2663 calls for open competition by December 31, 2000, a year before the ACC plan. HB 2663 also allows public power entities to participate in retail electric competition statewide, if they are willing to open their own service territories.

ARKANSAS - Utility and customer groups gave the Arkansas Public Service Commission widely divergent views of the timing of restructuring in comments filed February 17, 1998. At the same time there was general agreement on several issues including securitization and making retail choice optional for public power utilities.

The PSC agreed in late 1997 as part of a rate settlement to hold a general review of electricity competition issues during 1998. The PSC will draw up recommendations for the state legislature's 1999 session.

CALIFORNIA- California Public Utilities Commission (CPUC) authorized Pacific Gas & Electric to defer until Jan. 1, 2000, the offering of credits on electric bills for billing, metering and other services purchased from competing energy service providers and to instead issue refund checks.

The commission last year ordered PG&E and the state's two other electric investor-owned utilities to unbundle their revenue cycle servises by Jan. 1, 1999, in order to facilitate direct access and enable retail customers to choose their power suppliers.

The CPUC concluded that competition in metering and billing services is critical to facilitating direct access by enabling all stakeholders to have comparable access to the generation market and avoid cost shifting among different customer classes.

Earlier this year PG&E informed the CPUC that it would be unable to modify its billing system to accommodate the commission's unbundling requirements until mid-1999, and requested that it be allowed to delay making the required changes.

The CPUC agreed that the delay would create unnecessary confusion for customers and complicate marketing for PG&E's competitiors. Nonetheless, the CPUC agreed with PG&E that in order to upgrade its billing system by Jan. 1, 1999, the utility would have to divert substantial internal resources from other essential operations, which would not be cost-effective.

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California consumers support the right to choose their power suppliers and would defeat efforts now underway to repeal the law on the November ballot. Sixty-eight percent of Californians surveyed said they like being able to pick their energy provider even though only a fraction of them are switching suppliers, according to the June poll conducted by RKS Research and Consultants in New Salem, N.Y.

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The CPUC denied a petition by New Energy Ventures that the CPUC stop using a Power Exchange's average market clearing price in calculating the PX credit and the competition transition charge shown on consumer electric bills.

The PX credit and CTC have appeared as separate items on retail electric bills since the March 31 launch of retail competition. Their placement is meant to enable customers to determine whether they will save money by purchasing electricity directly from energy service providers rather than utilities.

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The CPUC authorized Pacific Gas & Electric and San Diego Gas & Electric to recover 1996 capital additions to their non-nuclear generating plants through the nonbypassable competition transition charge.

PG&E initially sought to recover $57.4-million in capital additions for 1996. The CPUC's Office of Ratepayer Advocates (ORA) and the Toward Utility Rate Normalization group challenged PG&E's request and recommended that it be reduced $12.6-million on grounds that the investments were not cost-effective or necessary to maintain PG&E's plant. The parties subsequently reached a settlement which reduced PG&E's request by $3.9-million.

SDG&E requested $14.5-million in 1996 capital additions which ORA recommended trimming by $1.6-million. SDG&E and ORA subsequently negotiated a joint recommendation allowing recovery of $13.462-million of the utilities's 1996 capital additions budget. The CPUC plans to a decision regarding Southern California Edison's capital additions later this year.

COLORADO - Colorado lawmakers suspended action on three measures designed to deregulate the state's electric power industry and opted to study the issue for another year. Lawmakers formed a task force and will study the issue until the 1999 session.

CONNECTICUT- Commissioners and staff of the Department of Public Utility Control (DPUC) held a technical meeting to kick off regulatory efforts to bring electric power competition to Connecticut. At the meeting the DPUC unveiled its plan for accomplishing all of the tasks necessary to implement legislation passed in the 1998 legislative session and signed by Governor John G. Rowland.

The new law institutes customer choice of electric suppliers beginning in 2000. The law also empowers the DPUC to make all of the regulatory changes and procedural rulings necessary to make electric supply competition possible and to oversee a consumer outreach and education program. Moreover, the DPUC must accomplish the legislative mandates according to a stringent time schedule.

Under "electric restructuring," CL&P and UI will continue to own the wires, transformers and many of the poles and conduits, known as the "distribution system," that bring the electricity to individual customers. They will be known as "distribution companies" and will continue to be regulated by the DPUC.

Competition among electric suppliers should produce greater choice and lower prices for consumers. Suppliers will be licensed by the DPUC, which will set guidelines for their Connecticut operations, but it is market forces, not the DPUC, that will regulate the rates charged by those companies.

In addition to the numerous cases the DPUC must conduct, the law mandates that the DPUC set into motion a campaign to assure that each segment of Connecticut's population will have the information needed to make educated choices for electric supply. The DPUC also announced its intention to provide ongoing consumer support, beyond the initial campaign, by adding staff to its Consumer Services Unit.

DELAWARE - The Delaware Public Service Commission issued its final report on competition, calling for competition among all customers to begin one year after restructuring legislation is signed into law.

Previously the DPSC staff had proposed a phase-in of competition in three blocks of customers. The state's industrial customers objected to this approach claiming that it would delay full competition until 2003 putting them at a disadvantage with competitors in other states that were opening competition sooner. The industrials were also concerned that the phase-in would cause competition problems within the state as some in-state competitors got access to cheaper electricity before others.

The DPSC's report recommends that retail access be implemented to all customers on an equal basis with a 12-month transition period to address such issues as stranded costs, consumer education and other operational issues.

Currently the DPSC regulates Delmarva Power and the Delaware Electric Cooperative. The report recommends the DPSC be given authority to regulated the state's nine municipals as well, "In order that all the state's customers can benefit from the competitive market."

At first the commission recommends only "functional separation" of generation from transmission distribution. However, if this approach is not successful in preventing cross-subsidization, then the PSC should have the authority to order "structural separation" of generation. Further the report calls for granting the commission authority to order divestiture to alleviate market power problems.

During an undefined transition period, the traditional utilities should continue as the "default" supplier for customers that do not choose an alternative provider but the PSC should have the discretion and authority to determine if and when an auction bid should be conducted for the default supplier status.

On stranded costs the PSC recommends that utilities be allowed to collect all of the "commission-approved, non-mitigable" stranded costs. That rejects demands from some intervenors that utility shareholders absorb half the costs.

The report also urges the legislature to consider tax-code changes in order to maintain the current level of tax revenues after restructuring. "State taxes from utilities and the new alternative suppliers of electric generation should be levied in a manner that does not discriminate between in-state and out-of state sources and does not impede the development of a fully competitive market for retail generation.

Finally, the report recommends that new generation suppliers contribute to the funding of the commission through the certification process.

FLORIDA - Several transmission-dependent utilities expressed concern about the efficiency and reliability of Florida's transmission grid during the Federal Energy Regulatory Commission's regional independent system operator conference.

The Florida Reliability Coordinating Council(FRCC) recently began work on developing an open-access transmission marketplace operated on a non-discriminatory basis, and the Florida Municipal Power Agency is dedicated to achieving that goal said FMPA General Manager John L'Engle. Yet, he doubts that Florida's largest utilities, including FP&L, will commit to resolving matters of governance, planning, ownership and operation of the transmission system in a reasonable period of time. Considering those obstacles, FMPA favors a FERC-mandated ISO. Seminole Electric Cooperative's Timothy Woodbury agreed.

FP&L warned that an ISO's one-size-fits-allapproach to system operation would fail to recognize the unique aspects of the state's power grid and could impose new, unnecessary costs on customers. These costs would be especially onerous and duplicative since the FRCC already performs most of the same functions as an ISO. The Florida structure continues to evolve to further the development of a robust wholesale market and FERC should allow this evolution to proceed.

Florida Public Service Commissioner, Susan Clark also weighed in against an ISO for the peninsula because of its isolation from the nation's grid. Only a 500-kV line into Georgia links Florida and the state's utilities generates almost all of their needs. Since Florida utilities sell only about 10% of their total output to wholesale customers, the ISO concept would not benefit the state.

In Florida, utilities plan their transmission systems on an individual basis. The FRCC then reviews the plans on an aggregated basis to identify any resulting constraints or bottlenecks. If any are found, utilities are asked to work things out between or among themselves. Utilities have historically done an excellent job of cooperating, but only in areas where they have common interests, like reliability.

Also, they have developed the voluntary Florida energy broker network in which power is bought and sold through a computer system that matches the highest buy bid with the lowest sell bid.

GEORGIA - The Georgia Public Service Commission (GPSC) has ordered two Southern Company affiliates - Georgia Power and Savannah Electric & Power - to analyze how industry restructuring will impact their 10-year integrated resource plans and future investment decisions.

The PSC also asked Georgia Power to submit a report on how the state transmission system will handle new power flows created by deregulation and said both companies should delay implementing cuts in reserve margins until the commission completes a restructuring-related study of reliability issues.

Under Georgia law, the two utilities must submit updated integrated resource plans every three years and seek approval by the GPSC. In return, they have the right to ask for GPSC pre-approval for spending on new resource acquisitions.

The two companies submitted proposed IRPs in February 1998, but the GPSC staff complained that the ten-year plans ignored the fact that the Georgia energy market was likely to be deregulated within that time frame, resulting in a major impact on the need for new resources.

So far the debates on restructuring in Georgia, the Southern Company affiliates have called for delay saying the state already has low prices and does not need retail competition. The GPSC is just beginning a formal investigation of the issue and the state legislature is not expected to consider a restructuring bill until 2000 at the earliest.

In the filings to the GPSC, company representatives said that the issue of restructuring was irrelevant to the planning effort and that they did not want to submit internal company data on the possible affects of decontrol.

The GPSC decided against a staff proposal to bar the companies from collecting stranded costs on new investments if they failed to carry out the studies. GPSC members said they were not sure they had legal authority for such a step.

On the reserve margin issue, staff complained that the two companies planned to reduce margins by 1.5% to 12.6% despite a June spike in Georgia power demand which almost forced the company to start cutting back supply. They said such a low level would also be out of line with neighboring utilities.

HAWAII - Due to its geographical location, the Hawaii Commission was not contacted.

IDAHO - Washington Water Power will launch a two-year customer choice pilot with 7,500 residential, commercial and agricultural potential participants in Hayden and Hayden Lake, Idaho and in Deer Park, Washington.

Called More Options for Power Service II (MOPS II), regulators recently approved last-minute changes in the program, which had been expected to begin May 1, 1998. The program offers five pricing options.

The major change, intended to increase participation by removing some of the risk for the customer as the short-term electric market fluctuates, was to place a cap at 2.65 cents/kWh on two of the price options: a Monthly Market Rate based on month-to-month market prices, and as Annual Market Rate. The cap is 10% above the traditional rate.

Another price option for consumers will be a fixed energy rate based on the Bonneville Power Administration's preference rate. A fourth option, the renewable resource rate, will allow customers to pay an increased amount monthly to help develop and operate renewable resources from fuels such as wood and wind. Customers also can remain with WWP's traditional service and existing pricing.

The plan was approved by the Idaho Public Utilities Commission. The program is scheduled to begin July, 1998.

ILLINOIS - The Illinois Commerce Commission (ICC) approved Commonwealth Edison's application to issue up to $3.4-billion in securitized bonds. The approval is based on Illinois' electric utility restructuring law passed in December 1997 that allows the utility to issue a total of $6.8-billion in asset-backed securities. ComEd could, therefore, sell an additional $3.4-billion in securitized bonds after August 1, 1999, if it gets ICC authorization.

The company plans to use 96% of the proceeds gained from the bond sale to refinance debt and repurchase stock. The remaining 4% will be used to cover fees associated with the transaction. Specifically, the company anticipates it will buy back 22 million to 33 million shares, representing 10% to 15% of its outstanding common stock.

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New rules promulgated by the Illinois Commerce Commission under the state's new Restructuring law, require Commonwealth Edison, Illinois Power and other Illinois companies to strive to provide electric service to individual customers based on defined performance targets.

The rules further require jurisdictional utilities to report system-wide reliability indices each year, thereby enabling the ICC to track the overall reliability of electric systems over a period of years and to identify trends of improving or declining reliability. In addition, the rules require utilities to report a defined set of worst-performing circuits.

The ICC said the uniqueness of the rules is in the agency's requirement that utilities monitor the interruptions of each customer and design their system to provide reliable service. Previous reliability rules focused on statistical averages, not on individual customer experiences.

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In the period since the Electric Service and Customer Choice and Rate Relief Act of 1997 was enacted, the Illinois Commerce Commission has set a rapid pace in implementing the legislation.

Since December 16, 1997, the commission has made decisions on a wide range of issues, including strengthening electric service reliability standards; requiring electric utility subsidiaries to compete on their own rather than using the marketing resources of the holding companies; approving the funding mechanisms to support basic residential energy service and environmental research and protection; advised approximately 400 Illinois municipalities on adjusting to the affects of rate reductions on local tax revenue.

In addition, the Commission selected Peter Hoffman of Deloitte & Touche as a neutral fact finder, to establish the market value of electric power and energy. The Commission has also facilitated discussions necessary to ensure that the services provided by the utilities allow the transmission and distribution system to function properly with the advent of consumer choice. Further, the Commission initiated proceedings to establish rules defining the way utilities will be structurally organized in a new competitive environment.

Other major items pending on the Commission's fast track are the following:

- Establishing rules requiring utilities and alternative suppliers to disclose the sources of electricity supplied and emissions attributable to those sources.
- Establishing standards for the entry of alternative retail electric suppliers into the Illinois market. The delicate balance between promoting competition and protecting small commercial and residential customers from unscrupulous operators is the subject of close scrutiny.
- Reviewing proposals which will allow electricity to be priced at different levels throughout the day to reflect the true, real time cost of producing and obtaining power.

The broad changes in the electric service industry, mandated by the new legislation, will also result in the ICC's undertaking an unprecedented public education program designed to inform average consumers and small businesses alike about the how, when and what of selecting alternative energy suppliers.

Finally, the most direct and immediate impact of the Commission's implementation efforts will be observed with the filing and approval of electric rate reductions for residential customers to take effect on August 1, 1998.

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The Illinois Commerce Commission approved rules designed to spur development of the electric market and eliminate anti-competitive arrangements between utilities and their affiliates. The new rules on non-discrimination in affiliate transactions were adopted in compliance with Section 16-121 of the Electric Service and Customer Choice Act of 1997.

The rules provide, among other things, that:

Electric utilities shall not provide their affiliates or customers of their affiliates with preferential treatment or advantages over unaffiliated companies or their customers, in responding to service requests, the availability of firm versus interruptible service or the imposition of special metering requirements or other terms and conditions in a tariff.

Transactions, not governed by tariffs, between an electric utility and its own affiliated interests, which are in competition with an alternative retail electric supplier, shall not discriminate, except for corporate support transactions and some services that have been declared competitive.

Electric utilities and their affiliates are prohibited from notifying customers or potential customers, directly or indirectly or advertise to the public that the utility provides an advantage in scheduling, transmission or distribution of electricity to affiliates and their customers.

A utility must process requests for similar services provided by the utility in the same manner and in the same time period for its affiliates and for unaffiliated alternative retail electric suppliers and their customers. If an electric utility offers its affiliates or customers a discount, rebate, fee waiver or waivers of ordinary terms and conditions for service under tariffs, it must also make the same offer available to unaffiliated companies and their customers.

The emergency rules will become effective on June 14. Final rules will be adopted later this year.

INDIANA - Cinergy, parent company of PSI Energy and Cincinnati Gas & Electric is planning to finance a campaign to encourage popular support for electric deregulation in Indiana during the 1999 legislative session.

Deregulation bills backed by Cinergy and American Electric Power died in the legislature the past two years largely, most observers agree, because of opposition from the state's three Indiana-based investor-owned utilities - Northern Indiana Public Service, Indianapolis Power & Light and Southern Indiana Gas & Electric, in addition to the state's 41 rural electric co-ops and consumer advocates.

IOWA - MidAmerican Energy has applied to the Iowa Utilities Board for authorization to conduct a customer choice pilot program for at least 15,000 Iowa residential customers and 2,000 small businesses.

Once approved, the two-year, 90-MW program will allow customers in a yet-to-be specified Iowa community to choose among third-party electric suppliers and have that energy delivered by MidAmerican.

The MidAmerican Electric Choice project will begin signing up customers in December, following a customer education program. In order to participate, businesses must have annual peak demand less than 4 MW. Under provisions of the program, participating customers can return to bundled service without charge provided they notify MidAmerican within a specified 15-day period and remain on bundled service for the remainder of the pilot program.

For companies that exceed the 4 MW threshold, a separate direct access pilot, called the Market Access Service project, is available. Introduced last September, the pilot plans to offer 60 MW during its first year of operation.

Thereafter, 15 MW will be added each year until the pilot ends, either January 1, 2005 or when the customer can secure direct access outside the program. The pilot is currently awaiting approval of the utilities board.

Approximately 50 of MidAmercian's largest industrial customers will be eligible.

KANSAS - Retail wheeling legislation is died in the 1997 session of the Kansas Legislature and its future in the state is unclear. The Legislature's task force on retail wheeling spent most of 1997 trying to hammer out a report that could work its way through the legislature and into law. The final report called for retail choice starting July 2001, set a 12-year period for recovery of stranded costs and allowed 50% of costs to be recovered by ratepayers to be securitized through a state bonding system.

On December 10, 1997 a "minority report" urged a go-slow approach was filed with the Legislature and most of the industry's key players had signed it. In addition, both Gov. Bill

Graves and Rep. Carl Holmes, the lawmaker who chaired the task force effort, urged caution.

The only thing the Legislature passed on the issue was a resolution urging Congress not to mandate retail wheeling but to leave resolution of the issue to the states.

KENTUCKY - On April 7, 1998 Governor Paul Patton signed House Joint Resolution No. 95 which creates an Electricity Restructuring Task Force, consisting of 10 members from the General Assembly and 10 from the executive branch, to study electricity restructuring and to report findings by November 15, 1999. The task force will study electric industry deregulation over the next 18 months to prepare for the next biennial legislative session in 2000.

LOUISIANA - Central Louisiana Electric (CLECO) has proposed to Louisiana regulators that the state adopt a phase-in approach to restructuring in which large users could opt for retail choice starting January 1, 2000.

Under the CLECO proposal, the state would then decide whether to go to full choice for all customers by January 1, 2003. Between 2000 and 2003, rates would be frozen and utilities would be able to receive stranded cost payments from the industrial users who chose alternative suppliers. Tax laws would also be modified to ensure equal treatment of all power producers.

The CLECO plan also recommends that pilot retail access programs for small users be carried out before 2003 to evaluate interest and educate the public.

CLECO said its plan, filed with the Louisiana Public Service Commission (LPSC) would give the state more time to study restructuring issues and design a system that could avoid pitfalls of other states. The plan would also protect small users from possible short term rate hikes if choice was introduced early and also give them more time to consider offers and avoid "fly-by-night" operators.

At the same time, CLECO said large users, with over 1,000 kW of load and who were more prepared to deal with the competitive market, could start choice quicker. This would protect Louisiana from losing jobs to other states that moved ahead with choice.

CLECO said its proposal was a "middle ground" between demands by consumer groups for full choice immediately and other utilities such as Entergy which has proposed a delay until 2004.

The LPSC is holding an inquiry on restructuring issues during 1998 and is expected to make final recommendations late this year or in early 1999.

MAINE- Central Maine Power shareholders May 21, 1998 endorsed a plan to restructure the utility to a holding company in preparation for electricity restructuring in Maine in March 2000.

The corporate reorganization had already been approved by the Maine Public Utilities Commission May 1, 1998 and will be implemented after final consent by the Securities and Exchange Commission and Federal Energy Regulatory Commission.

Under the two-stage plan, each existing CMP share will be exchanged on a one to one basis for a share in the new holding company to be called CMP Group Inc.

In turn CMP Group will become 100% owner of CMP, which will remain a regulated distribution and transmission affiliate after deregulation.

In its order approving the holding company, the Maine PUC placed several conditions on the new group. These include a $240-million cap on investment in non-utilities ventures which represents about 20% of current capitalization and rules on notification of asset transfers between affiliates.

It also ordered that the holding company borrowing be limited to 50% of total capital. CMP had agreed to the 50% limit for a five year period but the MPUC had refused to accept a time limit.

CMP Group will also own MainePower, a new non-regulated energy marketing company which will market energy in Maine and the rest of New England. MainePower will also hold CMP's generation assets until the divestiture is complete. CMP has already agreed to sell is generation assets to FLP Group and is awaiting PUC approval to complete the sale in late 1998.

A third division under the holding company will own other subsidiaries in the tele-communications, gas, accounts management and environmental engineering sectors.

MARYLAND - Utilities filed their restructuring plans with the Maryland Public Service Commission (MPSC) and they estimate that stranded costs will total about $1.9-billion. The MPSC will conduct hearings on the filings, and it expects to issue a final order by October 1999. The MPSC has called for retail competition to begin in July 2000, and to reach all consumers by July 2002, though the legislature must approve that change.

Potomac Electric Power is seeking $600-million, including $320-million in above-market generation, $242-million in above-market power purchase contracts, and $38-million in regulatory assets.

Stranded costs would be recovered through a competitive transition charge (CTC). From 2000 through 2005, the CTC would run 0.97-0.99 cents/kWh, then in 2006, it would drop to 0.5 cents/kWh for five years, and then drop to 0.1 cents/kWh through 2021.

PEPCO has calculated an average "shopping credit" of 3.6 cents/kWh in 2000, rising to 3.9 cents/kWh in 2003. This represents the generation portion of rates, against which outside suppliers must compete, and would vary by class.

Baltimore Gas & Electric (BG&E) expects stranded costs of about $1-billion, mainly related to its power plants. However no figure was filed with the MPSC. The final number will be determined by the market when it finally opens. BG&E has stated that no stranded costs will be passed on to customers. Instead, the company will absorb them through cost-cutting measures and accelerated depreciation. This will allow BG&E to freeze prices at year-end 1998 levels and hold them for at least four years. BG&E expects to complete the transition period - when book value of generating assets is within 10% of the market value - as early as 2004, and no later than 2008.

BG&E will not calculate a shopping credit until retail competition begins in 2000. The company will provide a "standard offer" to customers, which they can compare to rates from competitive suppliers.

Allegheny Energy is seeking $241-million in stranded costs, stated in 2000 dollars, since that is when the market will open. The average shopping credit will be 2.4 cents/kWh in 2001.

Delmarva Power is seeking $69-million in stranded costs for its Maryland service territory, and expects to collect those over three years. No shopping credit will be calculated until retail competition begins.

MASSACHUSETTS - Northeast Utilities completed a deal to provide about 100 MW for Boston-based aggregator National Energy Choice which has pooled businesses, schools, health care organizations and municipalities.

Select Energy, NU's unregulated retail marketing subsidiary, won the contract by offering savings of 10% to 14% below local utility standard offer rates. The NEChoice/SelectEnergy deal is one of few that have been struck since retail choice began in Massachusetts in March, 1998. Buyers and sellers say it is difficult to reach agreements because of uncertainty over a retail choice repeal question that will appear on the November general election ballot. Another problem is that distribution companies are offering below-market standard offer rates for customers who do not want to venture into the competitive market yet.

Select Energy will provide both power and energy efficiency services. The supplier was able to offer the savings on power because of the load profile of the buying group. NEChoice aggregated energy users with different usage profiles into one large block, and attempted to match every kilowatt of night time use with roughly four kilowatts of daytime use.

The 10% savings guaranteed by NEChoice and Select Energy to customers will be achieved by combining energy efficiency measures and discounted power. Customers can sign four or five-year contracts. Either way, they are guaranteed a 5% discount on power costs during the first four years. Customers who sign five-year contracts are guaranteed savings of at least 7% in the fifth year. The contracts allow for additional savings during the fourth and fifth years if the price of electricity falls lower than projected. The remaining savings will accrue through energy efficiency services.

The program does not guaranteed savings on transmission and distribution rates, although energy efficiency measures offered by Select Energy might also reduce those rates, according to NEChoice. The program also includes a bill consolidation program whereby customers with multiple facilities can receive one bill.

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Massachusetts utilities are using legal strategies and public campaigning to block an attempt to repeal the state's restructuring law.

Boston Edison and New England Electric System, along with associations representing power marketers, industrials and retail businesses have joined together to back a political committee called Keep the Electric Rate Reductions. The committee is campaigning against a November ballot question that would put an end to retail choice in Massachusetts.

The Campaign for Fair Electric Rates, a consumer group launched by Cambridge businessman John O'Connor, collected the necessary 32,000 signatures to place the repeal question on the ballot. O'Connor opposes the deregulation law because it allows 100% recovery of utility stranded costs.

Jon Hurst, president of the Retailers Association of Massachusetts, said the referendum question has had a "chilling effect" on the electric market, causing buyers and sellers to shy away from signing contracts. Hurst said the problem is particularly pronounced fro small to medium-sized retail companies in search of lower cost power.

The pro-competition group's first line of attack will be through the court system. The group recently argued before the Massachusetts Supreme Judicial Court that the restructuring law cannot be overturned through a referendum question.

The pro-retail choice group also has accused the Campaign for Fair Electric Rates of making unlawful changes to petitions used to gather the required signatures. Earlier this year, the Massachusetts State Ballot Law Commission rejected similar arguments made by the group, saying the changes to the petitions neither violated the state constitution nor influenced the outcome of the signature drive. The state Attorney General has written a letter to the SJC urging quick action on the court challenges.

If the pro-competition group loses in court, it plans to conduct a grass roots political campaign to defeat the referendum.

Meanwhile, the Campaign for Fair Electric Rates is also attacking deregulation on the regulatory front. In a petition filed with the state Department of Telecommunications and Energy (DTE), the group alleged that Boston Edison's standard offer discount was calculated from an inflated base. The 10% discount is based on the utility's's 1997 rates. The DTE rejected the petition, saying that the issues had already been fully explored in earlier proceedings, and that it lacks authority to litigate approved rates.

MICHIGAN - Consumers Energy will offer 300 MW of retail electric capacity for bidding this year under the Michigan Public Service Commission's retail wheeling program, with an additional 150 MW to be made available for direct access each year in 1999, 2000 and 2001. By 2002 all Consumers Energy customers will be able to choose their electric supplier.

Details of Consumers and Detroit Edison's direct-access implementation plans were explained at a April 17 meeting. The meeting was ordered by the Michigan Public Service Commission (MPSC) to have the two utilities, suppliers, the MPSC staff and jurisdictional customers work out the details of the direct-access program. Issues that cannot be resolved will be dealt with by the MPSC in a contested case.

Following review and deliberations by interested parties, Consumer Energy will seek MPSC approval of a revised restructuring plan and subsequent approval of the retail open access tariffs from the FERC.

Detroit Ed announced it will offer 225-MW blocks of capacity for direct access over five separate periods, culminating in 1,125 MW after January 1, 2001. Detroit Edison has expressed reservations about the MPSC restructuring orders and had challenged the agency's statutory authority to order direct access. The utility has said its plan is conditioned on the recovery of stranded costs.

Meanwhile, the March petition filed by the Assn. Of Business Advocating Tariff Equity (ABATE) requesting the MPSC to order the two companies to comply with the commission's restructuring orders is still pending. In the petition, ABATE charged that Detroit Edison is willing to use any means necessary to frustrate or delay open-access implementation in Michigan, while Consumers Energy is engaged in "major-league foot dragging" in terms of implementing the MPSC's restructuring orders.

MINNESOTA - During 1996 a work group created by the Minnesota Public Utilities Commission (MPUC) examined ways to bring wholesale competition to the state and to consider other near-term actions aimed at developing a more competitive electric industry in Minnesota. On October 18, 1996 the MPUC's Electric Competition Work Group (ECWG) issued its report concerning the establishment of robust wholesale competition in Minnesota, including participation in the Midwest Area Power Pool and the implementation of an independently operated regional transmission system.

During the 1997 legislative session, Senate File 1820 was enacted that establishes a task force to study electric industry restructuring. The task force is to issue a report to the Legislature by January 15, 1998.

MISSISSIPPI - A plan to start retail competition in Mississippi on January 1, 2001 has drawn fire from both sides in the restructuring debate, with utilities in the state calling for delay and industrial users saying the schedule could be speeded up a year.

Entergy Mississippi, in comments submitted to the Mississippi Public Service Commission (MPSC) said that the proposal floated by the state Public Utilities Staff to start retail competition in 2001 was "overly optimistic". Entergy said that in view of the complexity of the issues and need for a lengthy process to adopt a new state law it believed that January 2002 was the "earliest realistic start date for competition" in the state. Entergy also said the later date was advisable because of the need to work out technological and engineering requirements, pointing to the recent delay in California due to computer problems.

Southern Company affiliate Mississippi Power also complained that the plan to introduce retail choice in 2001 was "aggressive" and "would not allow time for Mississippi to learn from the successes or failures of other states."

At the same time, however, the Energy Consumers for Choice in Mississippi (ECCM), representing industrial users, noted that under the staff plan rates would be unbundled and bilateral contracting by retail users would begin by January 1, 2000. It said that there was no reason given in the plan why staff inserted a one-year delay between these steps and actual start of retail competition. "It appears that once rates are unbundled and the initial bilateral contract process begins that this should herald in retail competition.

Also ECCM claimed that the schedule proposed by staff could be accelerated by pushing back the review of utility stranded investment claims until after choice begins. This would eliminate the need for lengthy hearings during 1999 and allow for a better assessment of the actual positive and negative affects of deregulation on the utilities.

The MPSC is expected to decide by summer whether to support retail choice and make recommendations to the legislature.

MISSOURI - The final report of the Missouri Retail Competition Task Force calls for a cautious approach to deregulation in the state and makes no recommendations on some other key issues.

"Retail restructuring should proceed with caution and be completely within the control of the state," states the report by the task force. "By recognizing the preeminence of consumer choice and benefits, a transition to competition will require an understanding of the complexities that accompany such a move. The introduction of retail competition should proceed only if it can be shown to benefit all classes of consumers and should be implemented consistent with this goal."

While making some recommendations on specific stranded cost issues, the report ducks taking a bottom line stand, stating, "The Task Force takes no position on the issue of overall recoverability of stranded costs associated with implementation of competition."

However, the report does explore some areas where existing laws in other fields may collide with any new competitive environment. For example, the report recommends a change in the Missouri Sunshine laws, which currently require that records relating to the operation of the municipal utility be publicly available.

"The Task Force recommends that municipal utilities participating in a competitive retail market have the same information disclosure and open meeting requirements as other entities providing comparable competitive services; provided, however, that those municipal utilities should open records for public review when they are no longer commercially sensitive."

MONTANA - The stage is set for Montana Power Company's large customers to be able to choose their electricity suppliers beginning July 1 and for pilot choice programs for small customers to begin in November as a result of an order issued by the Montana Public Service Commission (MPSC).

The MPSC directed MPC to "unbundle" customers' rates to separate the supply portion from the delivery portion and implemented an accounting mechanism to track MPC's stranded costs from July 1 until the PSC makes a final decision on this issue in the second phase of this case, which will occur later this year after the company sells its power plants.

The commission also addressed issues affecting the transition of MPC's residential and small commercial customers to supplier choice. MPC's pilot program proposal for phasing in supplier choice for small customers was approved, except the PSC rejected MPC's proposed cap on the number of customers any single supplier could enroll in the pilot program. In the initial phase of the pilot programs, 5 percent of MPC's residential, commercial and irrigation customers will be eligible to sign up with the electricity suppliers of their choice on a first-come, first-served basis, starting in November. If the pilot runs smoothly in the initial phases, MPC will expand the pilot by another 5 percent of customers in June 1999, and by 10 percent in August 1999 and each month thereafter until all MPC's customers are eligible for choice by April 2000.

The MPSC also approved MPC's plan for educating customers about the coming changes to their electricity service. Denied as confusing to customers MPC's proposed "delivery service charge" to recover distribution costs. Instead, MPC was directed to continue the existing monthly service charge and recover the remainder of distribution and transmission charges through separate charges based on individual customers' usage. To help customers understand rate unbundling, MPC must provide informational worksheets to customers that show them how to compute their bills for each unbundled rate component.

Adopted standards of conduct for MPC to prevent the company from discriminating against competing suppliers in favor of its own affiliates.

Deferred a decision on whether entities other than MPC should be able to provide metering and billing services for customers. The commission will initiate a separate proceeding to consider these issues.

Issuance of this order ends the first phase of the MPSC's consideration of MPC's plan for electric restructuring that was filed last July. The company's announcement in December that it would sell its generation assets made it necessary for the MPSC to delay its final decision on "stranded costs" until the sale is completed. Stranded costs refer to electricity supply costs that are currently recovered in regulated utility rates but which would not be recoverable under the market prices that will prevail in the unregulated supply market. Because MPC has decided to sell its generation, the sale price will provide guidance as to whether and how much stranded costs MPC faces. Another issue to be taken up later is the company's proposal for a universal system benefits program to fund public purposes such as low-income energy assistance, conservation and renewable resources.

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The state Public Service Commission issued an order that implements the rate "unbundling" and stranded-cost accounting mechanism that must be in place so that PacifiCorp's seven large industrial customers will be able to choose their electricity suppliers beginning July 1, 1998.

The PSC "unbundled" PacifiCorp's rates for its large customers by separating the supply portion of their electricity rate from the delivery portion. The commission also instituted a mechanism to track the company's stranded costs between July 1, when the large customers move to choice, and the date of the PSC"s final order in this case, which will be later this year.

All the other issues involved in PacifiCorp's electric restructuring and transition plan, including transition costs, customer education and pilot programs, will be subjects of a PSC technical hearing in Kalispell beginning August 25. Evening hearings to obtain citizens' comments will be held in Kalispell and Libby.

PacifiCorp filed its proposed plan last July to restructure its electric operations pursuant to the Electric Utility Industry Restructuring and Customer Choice Act passed by the 1997 Montana Legislature. The new law provides for deregulation of the generation and sale of electricity to Montanans while electricity transmission and distribution will remain regulated. The new law requires PacifiCorp to offer its large industrial customers in Montana the opportunity to choose their electricity supplier by July 1998 and to plan pilot supplier choice programs for residential and small commercial customers. In its transition plan, however, Pacific Power proposes to forgo pilot programs and move all residential and small commercial customers to supplier choice in July 1999.

NEBRASKA - This unusual state with a unicameral legislature and 100% public power has begun a three-year legislative study of the state's electric power industry. The goal is to examine moves towards competition in the industry nationwide and develop alternatives to enhance the ability of Nebraska's public power industry to thrive in a competitive environment. Phase I of the study, to be completed by the end of 1997, will be an examination of the structure of the power industry in the state and issues facing the state's electric utilities. Phase II will be an in-depth analysis of issues related to competition and of possible policy changes to strengthen public power's position in the future. This phase will begin July 1, 1997 and be completed by the end of 1999.

NEVADA - In a major step toward bringing about competition in electric markets, the Nevada Public Utilities Commission (NPUC) determined that, in addition to generation and aggregation, billing, metering, and customer service will also be classified as potentially competitive services (PCS) in Nevada. Potentially competitive services are those services that may be offered to consumers by any licensed seller.

The action is a direct result of 1997 legislative approval of a far-reaching bill which paves the way for competitive electric service in the State no later than 1999. The bill had the backing of the then named NPUC, the state's major utilities and other stakeholders. Prior to the opening of competitive markets, the NPUC must conduct rulemakings to unbundle rates, identify stranded costs, establish licensing procedures for new market entrants, designate which services are PCS, and create various consumer protections and labeling requirements.

Nevada Revised Statute (NRS) creates two categories of components of electric service. They are non-competitive services and potentially competitive services. Non-competitive services include transmission, distribution, or any other component of electric service that the NPUC determines should be provided by a single company. PCS is any component of electric service determined by the NPUC to be suitable for purchase by customers from alternative sellers.

Aggregation (the service of buying electricity and reselling it to retail customers) and Generation were not evaluated by the NPUC since they were already classified by the Legislature to be PCS.

The NPUC, however, believed that billing, metering and customer service required analysis since they are necessary to the provision of retail functions of aggregation and generation services. The Commission solicited comments from interested parties and held three separate workshops before making a ruling.

The following criteria was used to determine if billing, metering and customer service were to be classified PCS:

- there will be no harm to any class of customers
- the cost of providing service to Nevada customers is likely to decrease and/or the quality or innovation associated with the service provided to Nevada customers is likely to increase or both
- effective competition is likely to develop in the market to provide the particular service
- it will advance the competitive position of Nevada relative to surrounding states
- it will not jeopardize the safety and reliability of electric services in Nevada.

The order does not authorize alternative sellers to begin offering PCS for sale to customers, that will be established in a future order. By indicating which services should be PCS early on, the Commission hopes indicate to legitimate alternative sellers that they will have a chance to do business in Nevada. All alternative sellers must obtain a license from the NPUC before they are allowed to sell any electric service to a customer. License procedures and conditions will be determined by the Commission in the near future. These procedures and conditions relate to: safety, reliability, financial reliability, fitness to serve customers, and billing practices and customer service.

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The NPUC to request additional comments from interested members of the public for proposed changes to Chapter 704 of the Nevada Administrative Code (NAC) in an effort to establish standards of conduct for distribution companies of electric and natural gas companies and their affiliates. Initial comments from standards of conduct for distribution companies of electric and natural gas companies and their affiliates. Initial comments from interested parties were obtained during a workshop on March 4, 1998 conducted by the NPUC. The final step in the rulemaking process is the adoption of the regulation which the NPUC is expected to do in the near future.

NEW HAMPSHIRE - The New Hampshire Public Utilities Commission (NHPUC) approved with some modifications a voluntary plan to start retail choice for the 36,000 customers of New England Electric System's (NEES) local affiliate Granite State Electric (GSE). NEES accepted the terms and NHPUC officials said choice for GSE users could start later in July.

This would bring an immediate rate reduction of up to 17% for GSE's users and would be the first shift to retail competition by any utility in New Hampshire.

The NHPUC, earlier, had approved the NEES plan to divest its generation assets to U.S. Generating although a final order has not been issued yet. The release of the final order would allow the FERC to proceed with final approval of the asset sale. If, as expected, the FERC acts quickly, NEES will be able to give an extra rate reduction to all its distribution customers based on the sale.

In its ruling the NHPUC accepted a revised GSE transition service proposal with rates starting at 3.5 cents/kWh in 1998 and rising to 3.8 cents/kWh in 1999 saying this was high enough to entice other marketers to compete in the GSE area.

The NHPUC also shortened the transition service term to two and half years from the four proposed by NEES and extended the service to all customers served by GSE including new load.

The NHPUC also made minor changes in stranded cost calculations eliminating an incentive payment and lowering the rate of return from 9.4% to 6.5%. It noted that NEES had obtained a favorable stranded cost settlement from the FERC and that extra incentives were not needed.

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A U.S. District Court has rejected a new request for delay by New Hampshire state officials, instead explicitly expanded a preliminary injunction against a state restructuring plan to include all utilities there.

Under the June 5, 1998 ruling, Judge Ronald Lagueux confirmed that plans by the NHPUC to begin retail choice were "frozen" until he hears a case on the merits of the state's market-based stranded cost methodology probably in November, 1998.

In particular, he said, the NHPUC cannot require utilities to file restructuring compliance plans and cannot force them to implement plans already filed. At the same time, Lagueux said his order would not block the NHPUC from approving plans in which utilities voluntarily agreed with the state on the terms for restructuring.

Lagueux had originally placed an injunction of the state's restructuring plan for Public Service New Hampshire in May 1997 saying he believed the state's approach was unconstitutional and likely to be struck down in his final ruling.

The order clears the way for the NHPUC to approve a plan for New England Electric System affiliate Granite State Electric to begin choice on July 1, 1998 under a voluntary settlement with the state.

NEW JERSEY - The New Jersey Board of Public Utilities adopted general auction standards and review criteria that will be applied to GPU and Rockland Electric's plans to sell their non-nuclear and all generating plants.

The standards were developed to ensure that competition among bidders is fostered, that the sale price of the generating plants is maximized while cost is minimized, and that the auction process provides bidders with flexibility to bid on a number of generating sites at once.

In addition, GPU and Rockland Electric, before selling any of their generating plants, will have to submit to the Board a summary of the auction proceedings and outcome to demonstrate that they have complied with all of the auction standards developed by the Board. In turn, the Board will be responsible for reviewing and approving the sale of the generating plants to the selected bidders.

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The New Jersey Board of Public Utilities accelerated the move to full competition in its final restructuring order. It also wants new suppliers to disclose their portfolios and emissions .

The final plan begins the restructuring process in October 1998 with full retail choice by July 2000.

NEW MEXICO - Texas-New Mexico Power Company (TNP) offered customer choice pilot for 560 of its 40,000 New Mexico customers. Customers in the towns of Alamogordo and Tularosa may select their electricity supplier for a two-year period starting May 1, 1998. However, TNP said that no alternative suppliers have come forward and detail of alternative suppliers "remains to be worked out." The bid process to supply the 1 MW of load available in this pilot is currently under review at the New Mexico Public Utility Commission.

The TNP pilot is the first such program to be approved by the NMPSC, which has mandated TNP open its New Mexico market to customer choice by the year 2000. The two-year pilot program will serve as a transition mechanism and will provide TNP the opportunity to perfect the technical aspects of customer choice.

During the pilot TNP will study how many people are interested in choosing their supplier, how often they change their purchasing decisions and what factors influence their decisions.

The customer base of Alamagordo was picked because it is representative of TNP's service area and because city officials have been involved in the process of developing the pilot program.

Currently, the state's electricity restructuring program is stalled, but TNP expects favorable legislation in the years ahead.

The New Mexico legislature tabled for at least a year a retail electric competition measure. The legislation, introduced by Albuquerque Republican representative Ted Hobbs, had the strong support of Public Service of New Mexico but the legislative committee determined it was not a fiscal issue and deferred the item until next year due to the short 30-day legislative session in 1998.

NEW YORK - The Federal Energy Regulatory Commission approved the New York Power Pool's proposal to establish an independent system operator. The single-state ISO is not ideal in that it has a "tendency to favor in-state participants," said FERC Chairman James Hoecker, but "the perfect shouldn't be the enemy of the good." The ISO gives unbundled service across eight utility systems and will facilitate the state's retail access program, Hoecker observed.

The only controversy in FERC's action came in relation to the New York State Reliability Council, which the state's utilities are establishing in conjunction with the ISO to ensure reliability of the transmission system. The structure of the council comprises 13 members, eight of whom represent transmission owners. Nine votes are needed to take action. This may offer the potential for transmission owners to dominate the council and perhaps the ISO as well.

In its order approving the ISO, FERC told the transmission-owningutilities, negotiating with other parties, to revise their governance procedures to reduce their own voting power.

FERC also ordered other changes, including barring a plan allowing transmission providers from ordering immediate implementation of local reliability rules without review or approval by either the reliability council or the ISO.

NORTH CAROLINA - Duke Energy announced that it has agreed to participate in "Alliance" a group of utilities exploring the potential for an independent system operator reaching from the Midwest to the Southeast.

Jim Hinton, Duke Energy's senior vice president for electric transmission said, "It seemed prudent for us to join the discussion" among the Alliance members, given that ISOs - if properly structured - could help maintain the interconnected transmission grid's reliability in a deregulated electric industry. Hinton emphasized that Duke Energy's decision to participate in the Alliance study does not imply that his company will automatically agree to join the ISO the study may lead to. The study is expected to be completed in June, 1998.

NORTH DAKOTA - February 1997, the North Dakota Public Service Commission adopted NARUC principles which will be used as a guide for the possible restructuring of the electric industry. The general principles emphasize that changes in the industry should occur only when they meet two goals - improved economic efficiency and serving the broader public interest.

OHIO - Electric industry deregulation was dealt a setback when primary election voters rejected a proposed 1-cent sales tax initiative to help finance that state's public schools. Defeat of the tax means the school funding issue will be sent back to state legislators, who have tried to find a way to comply with an Ohio Supreme Court mandate to scrap the current system for financing public education and rely less on property tax revenue, which accounts for nearly half of the annual education budget.

It also means the utility restructuring issue may not be taken up by the legislature in the next several months. Two deregulation bills were introduced in the legislature in March, 1998.
several months. Two deregulation bills were introduced in the legislature in March, 1998. Senate Bill 237 and House Bill 732 would open Ohio's $11-billion-a-year electric industry to competition on January 1, 2000. The legislation would create so-called "retail marketing areas." Customers would be aggregated into groups of 100,000 during a five-year transition period ending December 31, 2004. An estimated 75 RMAs would be formed.

In Ohio, electric utilities are directly affected by the school funding debate because they pay some of the highest property taxes in the state and are assessed at a higher rate than other businesses. Utilities contribute so heavily to public school financing in Ohio, accounting for 70% of the property tax revenue in some districts, that the deregulation issue has been linked with school financing from the beginning. Some believe it is possible that deregulation and school financing can now proceed along a dual track in the General Assembly.

OKLAHOMA- Oklahoma lawmakers passed Senate Bill 888 smoothing the way towards electric deregulation in the state by 2002. Governor Frank Keating has signed the measure.

The measure had almost derailed when disputes over provisions dealing with Grand River Dam Authority (GRDA) arose. GRDA is a major supplier in the bulk power market but has no service boundaries and receives no state funds. With almost 1,500-MW of hydro and coal capacity, it markets to municipal systems, cooperatives, government entities and a large number of industrial customers.

GRDA does not answer to either voters or the Oklahoma Corporation Commission, but only to a board appointed by the governor. SB 888 includes a provision putting the state treasurer and the state bond advisor or their designees on the board, increasing its size from seven to nine.

On the deregulation front, the bill makes no final determinations on how such major issues as stranded costs or tax implications are resolved. It does speed up and more clearly defines the study process that will lead to those solutions.

The bill also clarifies the status of supplier switching until competition arrives. Cooperatives, investor-owned utilities and municipal utilities will be unable to take customers from each other unless both utilities agreed to the switch. It also sets a moratorium on municipal utilities condemning and taking over the lines and customers of other utilities until July 2002 or when retail competition arrives, whichever is first.

OREGON - The Oregon Public Utility Commission approved a pilot open-access program proposed by PacifiCorp, but said the pilot would be re-evaluated in July if the company had few participants, as predicted by energy supplier and industrial customers who claim it is too expensive.

Under the pilot, the company will offer direct access to all large industrial customers and schools in Oregon. Residential and small commercial customers in Klamath County will have the choice of staying with PacifiCorp and choosing market-based pricing, renewable energy or other options. Eligible "portfolio" customers will receive an "order form" from PacifiCopr that lays out these choices. The form will also include prices from other suppliers interested in taking part in the program, but PacifiCopr will act as the middleman. PacifiCorp is unique because other utilities providing the portfolio approach have not opened their program to alternative suppliers.

Illinove Energy Partners have been certified to participate in the program but may not take part because it may be too expensive. The pilot program's pricing scheme is based on standard tariffs, and energy and transmission "credits" are subtracted from those tariffs to reflect the fact that other suppliers are providing energy and transmission.

The energy credit will remain the same throughout the pilot. Market prices for the duration of the pilot are expected to be about $21.63/ Mwh but PacifiCorp's energy credit is only $19.81/MWh. Wheeling charges of $1.50 to $2.00/ Mwh would have to be included in the final price. In addition, PacifiCorp will impose a penalty of $100/MWh if energy service companies' load forecasts are inaccurate.

PENNSYLVANIA - PP&L Resources filed suit in state and federal courts over the Pennsylvania Public Utility Commission's (PPUC) order rejecting rate recovery of $1.14-billion in PP&L Inc. stranded costs. But the PPUC commenced settlement talks aimed at defusing the litigation.

The utility originally asked to recover $4.5-billion in stranded costs, and an administrativee law judge recommended up to $4-billion, which PP&L accepted. The PPUC cut the total to $2.864-billion over 8.5 years, with a pretax return of 10.86% on the unamortized balance. The PPUC rejected PP&L's request for reconsideration, ruling the company's arguments had been addressed.

PP&L filed suit at the U.S. District Court, claiming violations of the U.S. Constitution and at the Pennsylvania Commonwealth Court, charging misapplication of the state's Electricity Competition Act. A separate action asks the state court to halt implementation of retail competition, because the PPUC has misinterpreted the act. Retail access is scheduled to start in January 1999, covering two-thirds of customers, and extend to the remainder in 2000.

PP&L complained that the PPUC used an inappropriate price forecast, which made its plants seem more valuable in the competitive market, thereby reducing stranded costs. It also says the commission set an arbitrarily high "shopping credit" of 3.73 cents. That represents the generation portion of rates that are open to competition, so a higher credit gives marketers a bigger opportunity to provide savings, and would hurt the utility's attempt to retain customers.

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Allegheny Energy has filed suits in state and federal courts, seeking to increase its recovery of stranded costs in Pennsylvania. Allegheny, which operates as West Penn Power in the state, asked for $1.5-billion, but the PUC granted only $524-million. The company requested a new hearing, pointing out that West Penn charges the lowest rates in Pennsylvania, averaging 5.7 cents/kWh, and that much of its stranded cost burden stems from independent power contracts, which were mandated by federal law.

But the PPUC rejected the request, saying "The majority of West Penn's petition merely reiterates arguments raised and already decided" in the original restructuring case. Part of the argument was that the PPUC should calculate lost revenues in determining stranded costs, instead of merely estimating the value of assets, such as power plants.

Following the PPUC rejection, Allegheny filed suit in the U.S.District Court for the Western District of Pennsylvania, and in state Commonwealth Court. The federal suit alleges unconstitutional taking of property, based on the PPUC's denying recovery of $200-million in independent power costs, from federally-mandated contracts. The PPUC decision also denied Allegheny the full rate recovery - granted earlier by the FERC - on its purchases from the Bath County Pump Storage plant in Virginia.

Further, transmission and distribution rate caps in the restructuring ruling deny the company full recovery of T&D, according to Allegheny. In the Pennsylvania court case, Allegheny claims that it is not being granted the recovery due to it under the state's Electricity Competition Act.

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The PPUC reaffirmed the restructuring plan for Metropolitan-Edison Company (Met-Ed). Earlier this month the PPUC approved the utility's restructuring plan in a non-binding poll. Met-Ed is a subsidiary of GPU, Inc.

Under the final plan, Met-Ed will provide customers who shop for their electricity a system average shopping credit of 3.757 cents per kilowatt-hour beginning in January 1999. Shopping credits will vary from one rate class to another and will increase over time to match anticipated increases in the market price of generation.

The plan allows Med-Ed to collect $975 million in stranded costs over 11 years, starting in January 1999, through a competitive transition charge.

The PUC directed that one-third of Met-Ed customers will be able to buy power from the supplier of their choice on Jan. 1, 1999, another third on Jan. 2, 1999, and the remainder on Jan. 2, 2000.

Starting in 1999, Met-Ed will unbundle its rates to reflect separate prices for the generation charge, the competitive transition charge, and transmission and distribution charges. While generation will be open to competition, Met-Ed will continue to provide transmission and distribution services to its customers at PPUC-regulated rates.

The action also significantly expands Met-Ed's funding of both the weatherization Low Income Usage Reduction Program (LIURP) and its Customer Assistance Program (CAP). The CAP program will be funded at $1.48 million in 1999; increase to $2.5 million in 2000; $3.5 million in 2001; and $4.56 million in 2002. The LIURP program will be funded at $1.23 million in 1999 and increase to $1.83 million by 2002.

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The PPUC also reaffirmed the restructuring plan for Pennsylvania Electric Company (Penelec). Earlier this month the PPUC approved the utility's restructuring plan in a non-binding poll. Penelec is a subsidiary of GPU, Inc.

Under the plan, Penelec will provide customers who shop for their electricity a system average shopping credit of 3.73 cents per kilowatt-hour beginning in January 1999.

The plan allows Penelec to collect approximately $858 million in stranded costs over eight years, starting in January 1999, through a competitive transition charge.

The PPUC directed that one-third of Penelec's customers will be able to buy power from the supplier of their choice on Jan. 1, 1999, another third on Jan. 2, 1999, and the remainder on Jan. 2, 2000.

Starting in 1999, Penelec will unbundle its rates to reflect separate prices for the generation charge, the competitive transition charge, and transmission and distribution charges. While generation will be open to competition, Penelec will continue to provide transmission and distribution services to its customers at PPUC-regulated rates.

The action also significantly expands Penelec's funding of both the weatherization Low Income Usage Reduction Program (LIURP) and its Customer Assistance Program (CAP). The CAP program will be funded at $2.42 million in 1999; increase to $3.3 million in 2000; $4.1 million in 2001; and $4.9 million in 2002. The LIURP program will be funded at $972,000 in 1999 and increase to $1.9 million by 2002.

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Customers served by UGI Utilities (UGI) will receive a system average shopping credit of 3.67 cents per kilowatt-hour (kWh) in 1999 and 2000, under a settlement restructuring plan approved by the PPUC.

Customers will save money if they purchase electricity for less than the shopping credit. UGI's shopping credit will increase to 4.3 cents per kWh in 2001 and 2002 to match anticipated increases in the market price of generation.

In addition, UGI will commit $150,000 over 18 months to initially fund a Customer Assistance Program to aid certain low-income customers in maintaining electric service. The company will also increase funding to its existing weatherization program, the Low Income Usage Reduction Program, by $15,000 per year.

The restructuring plan allows UGI to collect $32.5 million in stranded costs over four years, starting in January 1999, through a competitive transition charge.

Beginning January 1, 1999, all UGI customers will be able to choose their electric generation supplier. UGI will unbundle its rates to reflect separate prices for the generation charge, the competitive transition charge, and transmission and distribution charges. While generation will be open to competition, UGI will continue to provide transmission and distribution services to its customers at PPUC-regulated rates.

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Customers served by the Pennsylvania Power Company (Penn Power) will receive a system average shopping credit of 3.73 cents per kilowatt-hour in 1999, under the company's restructuring plan approved by the PPUC.

In addition, Penn Power will commit $500,000 to initially fund a Customer Assistance Program to aid certain low-income customers in maintaining electric service. The company will also increase funding of its Low Income Usage Reduction Program from its current level of $180,000 to approximately $645,000 over a three-year period.

The restructuring plan allows Penn Power to collect $234 million in stranded costs over seven years, starting in January 1999, through a competitive transition charge.

The PPUC directed that one-third of Penn Power customers will be able to buy power from the supplier of their choice on Jan. 1, 1999, another third on Jan. 2, 1999, and the remainder on Jan. 2, 2000. Penn Power will unbundle its rates to reflect separate prices for the generation charge, the competitive transition charge, and transmission and distribution charges. While generation will be open to competition, Penn Power will continue to provide transmission and distribution services to its customers at PPUC-regulated rates.

Customers served by Citizens' Electric Company (Citizens') will receive a system average shopping credit of 4.13 cents per kilowatt-hour (kWh) in 1999, under a settlement restructuring plan approved by the PPUC.

Phase-in will begin on February 1, 1999, for two-thirds of Citizens customers. All customers will have the opportunity to select their generation supplier on January 2, 2000.

The utility has also agreed to meet with representatives of the Dollar Energy Fund and the Low Income Usage Reduction Program to discuss universal service programs.

Citizens did not claim any stranded costs in its restructuring order. However, the settlement contains a provision that allows Citizens to seek authorization from the PUC to recover from its customers any stranded costs imposed on it by Pennsylvania Power & Light, its wholesale power supplier.

Starting in 1999, Citizens will unbundle its rates to reflect separate prices for the generation charge, the competitive transition charge, and transmission and distribution charges. While generation will be open to competition, Citizens will continue to provide transmission and distribution services to its customers at PPUC-regulated rates.

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The Public Utility Commission today took final action on The Joint Petition for Full Settlement of PECO Energy Co.'s Restructuring Plan, adopting the terms and conditions of the settlement approved April 30 in the form of a tentative order.

Final approval of the settlement guarantees all PECO customers an eight percent rate reduction effective Jan. 1, 1999, and a six percent reduction from January 1 to Dec. 31, 2000. In addition to the guaranteed rate reductions, residential customers who shop will receive a shopping credit of 5.09 cents per kilowatt-hour, with a system average shopping credit of about 4.46 cents per kilowatt-hour for the years 1999 and 2000. Shopping credits will vary from one rate class to another. On average, customers could realize a savings of up to 22 percent in 1999 on their electric bills.

Under the order, PECO can recover $5.26 billion in stranded costs from Jan. 1, 1999 through 2010, through a competitive transition charge, which will be adjusted yearly. The order permits PECO to securitize $4 billion of the $5.26 billion in stranded costs.

In addition to the rate reductions and substantial shopping credits, the settlement calls for transmission and distribution rates to be capped at 2.98 cents per kilowatt-hour to June 30, 2005; an extension of the generation rate cap to Dec. 31, 2010; provisions to provide for competitive metering, meter reading, and billing and collection services; competitive safeguards to insure fair and non-discriminatory competition, and the expansion of universal service programs and economic development.

One-third of PECO's customers will be able to buy power from the supplier of their choice on Jan. 1, 1999; another third on Jan. 2, 1999, and the remainder of Jan. 2, 2000. Open enrollment will begin on July 1.

RHODE ISLAND - Narragansett Electric, a Rhode Island subsidiary of New England Electric System (NEES), agreed to provide rate discounts for all of its customers with the start of retail competition January 1, 1998.

The discounts, which average 17%, are the result of a push by the Rhode Island Public Utilities Commission (RIPUC), which wanted all ratepayers to experience some reduction in rates with the advent of retail choice.

Customers can receive the discounts by buying utility standard offer power, a temporary offering for customers who do not feel comfortable venturing into the competitive marketplace during the early years of competition. NEES is selling off all of its generation assets, so will buy power through competitive solicitations to supply the SO.

Narragansett's SO rate has been controversial because independents, industrials and other pro-competition forces have charged that it is so low that it will keep alternative suppliers out of the state and delay development of a competitive market. Large industrials and government customers became eligible for retail choice July 1, 1997. Remaining customers could choose their suppliers beginning January 1, 1998.

The utility will initially offer what it describes as a "hybrid" standard offer, with rates varying according to customer classes. The variable rates will be discounted, and uniform standard offer rates instituted, when the utility completes sale of its generating assets to U.S. Generating in 1998. U.S. Generating has agreed to buy the 5,000 MW in non-nuclear assets for $1.59-billion, $500-million over book value. NEES will use the profit to reduce its stranded-cost charge.

Once the stranded-cost charge is decreased, creating a new form of customer savings, the utility will begin offering uniform SO rates for all customer classes.

The standard offer will only be available to customers who have not chosen a competitive supplier, or who notified the utility by November 28 that they plan to leave their competitive supplier and return to utility service.

SOUTH CAROLINA - South Carolina lawmakers considering restructuring legislation heard testimony that utilities would face dramatically different levels of stranded costs when full competition is enacted.

On the high side, the Piedmont Municipal Power Agency, whose 10 members own a 282-MW stake in Duke Power's Catawba nuclear station, faces a $2.8-billion stranded-cost liability, according to one estimate. That amount is about two-thirds of the total stranded costs of the state's electric suppliers.

The muni group said its analysis showed its wholesale power costs would not drop below projected market prices "for as long as PMPA bonds are outstanding, which is until 2026."

Meanwhile the South Carolina Public Service Commission (SCPSC) told legislators that it estimates the stranded costs faced by the state's three investor-owned utilities - Duke, South Carolina Electric & Gas, and Carolina Power & Light - would total $1.5-billion if full wholesale and retail competition were to begin in 2002.

At the IOU's request, the SCPSC did not specify estimated stranded costs for each of the IOU's. However, bond-rating agencies have suggested that Duke's stranded costs will be minimal, SCE&G's will be relatively small and CP&L's will be relatively high compered to other IOUs in the southeast.

State-owned Santee Cooper, in turn, told legislators that it estimates its own stranded costs at $227-million. The electric cooperative to which Santee Cooper sells wholesale power said they need more time to provide estimates.

The spokesman for South Carolinians for Competitive Electricity said that munis that are not part of PMPA, including those in Greenwood, Seneca and Orangeburg, are among the healthiest financially, in part because they avoided investments in nuclear power and in recent months turned to the competitive wholesale market for low-cost power.

With stranded-cost estimates in hand, legislators plan to continue their exploration of various retail-wheeling issues. South Carolinians for Competitive Electricity and other supporters of customer choice said they are optimistic that legislators in 1999 will approve a bill to phase in retail wheeling for residential, commercial and then industrial customers, possibly between January 1, 2000 and January 1, 2001.

SOUTH DAKOTA - As of October 1995, the South Dakota Public Utilities Commission was not investigating retail wheeling or restructuring.

TENNESSEE - A Department of Energy advisory committee on the Tennessee Valley Authority electric system has issued a final report calling for more regulatory controls on TVA once national electric deregulation begins.

The panel also said TVA should remain "mainly" in the wholesale electric business in the future but was unable to agree on several other key legal and market structure issues.

The DOE panel's final report calls for changes in TVA's status and especially favors allowing TVA to retain its current customers under more flexible contracts. Representatives of investor-owned utilities on the panel still expressed strong concerns about alleged unfair TVA competition once markets are opened and called for continued strong restrictions on its operations beyond those agreed by the panel.

In its report, the panel agreed on use of an excise tax on power sales to replace the current system in which TVA power is not subject to federal and state taxes but makes a payment in lieu of taxes. Also, the group said TVA should be subject to Federal Energy Regulatory Commission transmission rules.

On a third key issue, the group generally agreed TVA should lose its exemption from federal anti-trust laws, but TVA said it should still not be subject to the same fines and penalties as other utilities.

The group also agreed TVA should no longer regulate the retail energy markets in its home area but the parties disagreed on who should assume this function.

On key market issues, the parties could not agree on whether TVA could build new generation, under what conditions the "fence" blocking TVA sales outside its territory should end, when outside groups could begin selling in the TVA area and whether TVA could make retail sales either inside or outside its territory.

TVA and its distributors agreed on a plan under which current wholesale contracts would remain in place after deregulation subject to revisions to be determined later this year. But the other parties said any such revisions should be subject to FERC review.

The group also agreed in general that TVA should collect stranded costs from wholesale and retail users but subject to FERC review and a 10-year cut off.

TEXAS - The Public Utility Commission of Texas (TPUC) approved most elements of a rate and competition plan negotiated by Texas-New Mexico Power (TNP) that will cut the company's rates over a five-year transition period, accelerate depreciation of the company's sole generation asset and ultimately free the company's customer's to take service from other suppliers. Approval of the agreement by the TPUC makes TNP the first company in Texas to commit to opening its customer base to retail competition.

The basic rate cuts under the agreement total about $60-million over the five years, implemented as an immediate 3% cut for residential customers retroactive to the beginning of 1998 and additional reductions in 2000 and 2002 for a total of 9%. Commercial customers will receive reductions totaling 3% by 2002. Industrial customers will not receive any rate reduction.

The accelerated depreciation measure allow the company to apply an extra $15-million in depreciation to the lignite-fired TNP One plant in each year of the transition period except the current year. And this $60-million in accelerated depreciation can be increased through an earnings cap provision that splits excess earnings between additional rate reductions for ratepayers and additional depreciation for the company.

With the cap set an 11.25% return on equity, excess earnings could provide for about $13-million in additional accelerated depreciation and more than $21-million in additional rate reductions.

The company does not believe the accelerated depreciation will cover the entire stranded cost associated with TNP One and has asked for a wires charge to begin at the end of the transition period. The TPUC decided against approving any kind of wires charge at this time. Instead the TPUC ordered TNP to return with a filing in 2002 that formally requests implementation of the retail choice plan and describes how the remaining stranded costs may be recovered.

Although the TPUC did not mandated how the final stranded cost should be resolved language in the order indicated a preference for a market-based methodology for valuing the asset.

Between now and the end of TNP's transition period, the biennial Texas Legislature will meet twice and may well adopt a restructuring plan for the entire Texas electric industry. Provisions in the TPUC's order ensure that the TNP plan will conform with any legislation that is passed by the legislature during the next five years.

UTAH - A Utah legislative panel has voted to delay electricity competition legislation by at least one year. The panel decided - with strong support from Governor Michael Levitt - to adopt a "go slow" approach and require more study.

The vote to delay follows six months of hearings by the Electric Deregulation and Customer Choice Task Force, an appointed body of Utah lawmakers and clashes with efforts to introduce competition by the Utah Public Service Commission (UPSC), which concluded its analysis in September, 1997.

The UPSC analysis, initiated in January 1996, found that deregulation would be largely beneficial to end-users, but the task force found too many unanswered questions about the

The UPSC analysis, initiated in January 1996, found that deregulation would be largely

VERMONT - When the 1998 session opened in January, three House bills were introduced. The first, H.663, embodied the recommendations of the special House Electric Regulatory Reform Committee. The second, H.675, sponsored by twenty-two Representatives, adopted the key elements of S.62, but framed most of the provisions as general mandates, rather than detailed program descriptions, and delegated rule making authority to the PSB for implementation. Restructuring plans were to have been filed by utilities no later than Sep. 1, 1998, with retail competition implemented utility by utility, no later than Jan. 1, 1999, unless the Board did not find various conditions were met. Finally, H.701, favored by a group of large businesses proposed a more streamlined system, mandating retail access by 1/1/2000, unbundled rates, and a presumption of 50/50 sharing of above market stranded power costs with the MOU mitigation amount as a floor. Public benefit programs were limited to a pair of energy efficiency and renewable generation loan programs.

Although the subject of numerous hearings by several House Committees, none of these bills passed or were even voted out by a committee, nor was S.62 taken up by the House. The Legislature adjourned in April without taking action on restructuring, nor were any further study committees established. All the above mentioned bills then died as Vermont's biennial legislation session ended.

VIRGINIA - Asserting there should be "a continuum of decision making" by Virginia regulators over the next few years "so that an increasing level of competition corresponds with a diminishing level of regulation," the staff of the State Corporation Commission (SCC) expressed obvious worry about the seemingly fixed restructuring schedule established recently by the General Assembly.

In comments to a special legislative panel developing bills to restructure Virginia's electric industry, the SCC staff said that it "continues to have concerns with respect to the potential impact of restructuring," and that "we believe it is essential that legislation not treat restructuring as a one-time, final decision."

It continued, "Reductions in regulations should not be made at the initial stages of the restructuring process prior to the development of competitive forces that adequately provide the protections that have been afforded Virginia consumers through regulation.

That approach seems to be at odds with the fixed schedule in a bill approved by the General Assembly and signed by Governor Jim Gilmore. That bill calls for the development of an independent system operator and regional power exchange by Jan. 1, 2001; the deregulation of generation and the beginning of a transition to retail competition on Jan 1, 2002; and full retail wheeling on Jan 1, 2004.

The SCC staff said in its recent comments that "authorized competition is not the same thing as having competition," and that " effective competition depends on factors yet in place in Virginia."

Among other things, it said, the state now lacks "a sufficient number of competitors, one or more independent system operators and power exchanges, educated customers and new metering and regional mechanisms necessary to assure reliability and accountability. These market factors may be in place before 2004; or they may still be absent.."

The commission staff raised particular concern about the industry's current organizational structure and resulting physical infrastructure, which it said "present the potential for enormous incumbent market power in the initial stages of restructuring."

The staff also expressed worry that under a competitive environment, "each seller would have responsibility only for the customers signed up with that seller," leaving unclear whether any single entity would be responsible for ensuring that sufficient generation remained available for the state as a whole.

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Virginia Power announced it had reached a rate settlement with the staff of Virginia's State corporation Commission and others that would lower and then freeze the utility's retail rates, and allow it to use "excess" earnings to pay down part of its more than $2-billion in stranded costs.

If approved by the SCC itself later this year, Virginia Power will provide $150-million in retail rate refunds for the period from March 1, 1997 to March 1, 1998; reduce rates for the period from March 1, 1998 to March 1, 1999. After that, Virginia Power will freeze rates at the lower level through March 1, 2002.

The settlement with the staff of Virginia's SCC, the state Attorney General's office and the Virginia Committee for Fair Utility Rates also would reduce Virginia Power's rate of return to 10.5% from 11.4%

The settlement would allow Virginia Power to use two-thirds of any excess earnings up to 13.2% to write off regulatory assets, and to use all earnings beyond 13.2% to do the same.

The deal also calls for writing off regulatory assets in a certain order, beginning with deferred capacity expenses; followed by un-amortized losses on re-acquired debt and preferred stock; and then by the generational-related portions of the balances of the utility's Surry and North Anna nuclear steam-generator replacement costs, asbestos-removal costs, and North Anna electric-generator replacement costs.

These write-offs, which the settlement said must total at least $220-million over the period, are expected to help Virginia Power prepare for retail wheeling and to reduce the magnitude of any per-kWh transmission/distribution fee or other mechanism that might be used to pay down the balance of the utility's stranded costs.

The settlement grew out of a long-running investigation by the SCC into Virginia Power's retail rates and earnings, which the commission staff, industrial customers, consumers groups and others have alleged for some time are higher than they should be.

WASHINGTON - Washington Water Power July 1, 1998 will launch a two-year customer choice pilot with 7,500 residential, commercial and agricultural potential participants in Hayden and Hayden Lake, Idaho and in Deer Park, Washington.

Called More Options for Power Service II (MOPS II), regulators recently approved last-minute changes in the program, which had been expected to begin May 1, 1998. The program offers five pricing options.

The major change, intended to increase participation by removing some of the risk for the customer as the short-term electric market fluctuates, was to place a cap at 2.65 cents/kWh on two of the price options: a Monthly Market Rate based on month-to-month market prices, and as Annual Market Rate. The cap is 10% above the traditional rate.

Another price option for consumers will be a fixed energy rate based on the Bonneville Power Administration's preference rate. A fourth option, the renewable resource rate, will allow customers to pay an increased amount monthly to help develop and operate renewable resources from fuels such as wood and wind. Customers also can remain with WWP's traditional service and existing pricing.

The plans were approved by the Washington Utilities and Transportation Commission.

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In a move that could aid lawmakers should the state take steps to deregulate the electric power industry, the Washington legislature has passed a bill calling for the utilities to submit studies on unbundling their costs. The bill was partially vetoed by the Governor on April 2, 1998.

The Washington Public Utility District Assn. supported passage of HB-2831, which also requires utilities to prepare a cost, service quality and reliability report to be presented to the legislature. Exempt are small, consumer-owned utilities with no more than 25,000 meters in service, or an average of no more than seven customers per mile of distribution line.

Each investor-owned electric utility must file studies by September 30, 1998 with the Washington Utilities and Transportation Commission. Consumer-owned utilities must submit by September 1, 1998 a report to their governing bodies and by October 1 to the state auditor. By December 1, the WUTC and the state auditor are to submit a joint report on study results to the legislature.

WEST VIRGINIA - West Virginia's Public Service Commission (WVPSC) has begun its formal investigation into possible electric-industry restructuring, and has received proposals from utilities, industrial energy users and other stakeholders.

The WVPSC's probe grew out of recent state legislation that designates the commission as "the appropriate agency" to determine whether West Virginia should adopt retail competition if it finds customer choice of electricity suppliers to be in the public interest. However, the law also says that if and when a retail wheeling plan were proposed by the WVPSC, the plan should be either approved by the legislature or rejected and returned to the commission with "the reasons for such rejection."

In the restructuring proposal it recently submitted to the WVPSC; American Electric Power proposed that West Virginia implement customer choice no earlier than January 1, 2000, and perhaps a year or two later. AEP also proposed customers be provided with the right to choose their suppliers at the same time.

Customers would be permitted to continue receiving service from their current suppliers at the same rates they now pay during a subsequent five-year transition period.

It suggested that AEP and other utilities recover most of their stranded costs during the transition period - preferably through the collection of a non-bypassable transmission charge - and that any balance be recovered through a smaller charge over the following five years.

Allegheny Power made a similar proposal, calling for customer choice to be phased it between January 2000 and January 2002; for freezing rates through December 2004 for customers who decide to remain with their incumbent utility; and for recovering stranded costs through a wires charge.

A group of large industrial energy users proposed that retail competition be implemented for all customers on January 1, 2000. The proposal also called for a four-year transition period through December 2003 during which rates would be capped to protect smaller customers and a wires charge would be levied to pay off all or most stranded costs.

Under the industrials' proposal, the WVPSC would retain the option to extend the rate cap for four additional years - until December 31, 2007 "upon a finding that continuation of the...cap is necessary due to lack of meaningful choice." During this period, any remaining stranded costs would be payed off.

Finally, on January 1, 2009, full retail competition would be in place, with no rate cap - again save a finding by the PSC that meaningful choice was not available to small customers.

The PSC's investigation is expected to continue for several months, and to result in a restructuring and deregulation proposal in early 1999. That proposal will be reviewed by the state legislature.

WISCONSIN- The Wisconsin Public Service Commission (WPSC) has completed its investigation into the development of an independent system operator (ISO) and has concluded that Midwest ISO (MISO) is deficient based on WPSC principles.

The WPSC's order describes principles that pertain to control area operation, governance and planning and construction of transmission facilities. It then finds that the Midwest ISO proposal is deficient under the control area operations and governance principles.

The ISO should be a control area operator, the WPSC said. It should possess the authority to control or delegate authority over control area functions. But the MISO, as proposed, is not a single control area with operational control over transmission and generating facilities. "This structure presents a risk of creating a real opportunity to deny transmission capacity to other users...," the WPSC said.

The WPSC's governance principle states that an ISO should be managed by an independent board of directors, and should minimize the risks of discriminatory access to transmission capacity and of data concerning available capacity. And it should penalize noncompliance with the open access, nondiscriminatory transmission of electricity under applicable federal tariffs.

However, under the MISO agreement the power of transmission owners is sufficiently great to compromise the independence of the board of directors, the WPSC concluded.

With respect to other principles, the commission found that as ISO should play a "significant role" in the planning and construction of electric transmission facilities and should be consistent with FERC ISO principles.

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The WPSC has refused to lift its order requiring Wisconsin Power & Light to file with the
FERC the independent system operator (ISO) proposal crafted by Wisconsin Public Power Inc. (WPPI).

WP&L had asked the WPSC to reconsider its order and let it join the Midwest ISO instead. Although the PSC held firm to its previous ruling, it did, grant WP&L the right to file the Midwest ISO proposal along with the one by WPPI.

On Nov. 4, 1997 the WPSC conditionally approved the merger of WP&L, Interstate Power and IES Utilities to form Interstate Energy Corp (IEC). The WPSC, concerned about potential market power, ordered WP&L to join a regional ISO, form a single-system ISO or spin off its existing transmission assets into a separate independent transmission company.

WP&L created a system-specific ISO and submitted this plan to the WPSC. The WPSC found the proposed ISO was deficient in terms of control area operations, independent governance and transmission planning and construction. The PSC then ordered WP&L to file the WPPI ISO at FERC. The WPSC had previously determined that the WPPI ISO met its ISO standards.

WP&L appealed the decision, arguing that because of WPPI's comparatively small size and specialized focus that the ISO was not representative of the needs and interests of the Wisconsin entities and that it was unlikely to attract enough members to create a regional ISO.

WYOMING- In May 1996 the Wyoming Public Service Commission began a collaborative process with all stakeholders interested in electric restructuring issues. As a result of this process the Wisconsin PSC released a White Paper addressing restructuring, November 12, 1996. One of the recommendations in the paper was to conduct a comprehensive study of the economic impacts that electric restructuring might have on the State of Wyoming and its economy. February 20, 1997 Black & Veatch was chosen to conduct the study. A final report was issued in August 1997.

Sources: This table has been compiled from a variety of sources including Electric Utility Week, Public Utilities Fortnightly and state commission and legislative Internet websites.

NATURAL GAS INDUSTRY
RESIDENTIAL PILOT PROGRAMS AND UNBUNDLING INITIATIVES

STATE	COMPANY	POTENTIAL # OF HOMES	POTENTIAL DEMAND (Bcf)	IN-SERVICE DATE	PENDING OR COMPLETED GOVERNMENT ACTION*
Arizona					Commission Docket
California	Pacific Gas & Electric	3,454,000	190.9	03/98	CPUC Rulings Issued
	San Diego Gas & Electric	68,000	3.6	08/91	Changes Anticipated With
	Southern California Gas	455,000	24.0	In-Service	Gas Strategy OIR
Dist. Of Columbia	Washington Gas	3,000	0.4	01/99	
Colorado	Public Service of Colorado				PUC Hearings Held
Connecticut					PUC Hearings Held
Georgia	Statewide	1,538,000	127.7	11/98	State Law Passed
Illinois	Central Illinois Light Company	10,000	1.5	10/96	ICC Hearing
	Nicor Gas	10,000	1.5	2000	
	Peoples Gas Light & Coke	20,000	7.0	11/97	
Indiana	Northern Indiana Public Service Co.	80,000	6.1	05/98	URC Study Completed
Iowa	Statewide	770,000	87.8	02/99	IUB Rulemaking
	MidAmerican Energy	875	0.1	11/95-10-96	
Kentucky					Proposed Legislation
Maine	Northern Utilities	15,000	1.0	11/99	PUC inquiry
Maryland	Baltimore Gas & Electric	25,000	2.5	11/97	PSC Recommendations
	Columbia Gas	10,000	1.0	11/96	Issued
	Washington Gas	100,000	10.0	11/96	
Massachusetts	Bay State Gas	83,000	8.0	11/96	Unbundling Collaborative
	Boston Gas	479,000	46.0	11/97-2000	Workshops
Michigan	Battle Creek Gas	1,000	0.1	04/97	PSC Hearings Being Held
	Consumers Energy	300,000	42.8	04/98	
	Michigan Consolidated Gas	1,078,000	162.0	04/97	
	SEMCO Energy	2,500	0.4	04/99	
Minnesota	Great Falls Gas	22,600	2.4	Sep-99	PUC Working Groups
Montana	Montana Power	120,000	13.0	winter 1999	State Law, PSC Proceeding
Nebraska	KN Energy	100,000	22.0	06/98	Localities Regulate Utilities
New Jersey	Elizabethtown Gas	10,000	1.0	11/97	State Energy Plan &
	New Jersey Natural Gas	350,000	36.3	04/97	BPU Order Issued
	Public Service Electric & Gas	300,000	30.5	06/97	
	South Jersey Gas	13,000	1.0	08/97	
New Mexico	Public Service of New Mexico	361,000	28.5	12/97	
New York	Statewide	4,048,000	404.8	In-Service	PSC Regulations Issued
Ohio	Cincinnati Gas & Electric	360,000	30.0	10/97	State Law Passed
	Columbia Gas of Ohio	1,150,000	143.8	04/97	
	Dayton Power & Light	25,000	3.1	11/98	
	East Ohio Gas	1,034,000	129.3	04/98	
Oklahoma	Oklahome Natural Gas	670,000	59.0	05/98	Proposed Rulemaking
Oregon					OPUC Stated Objectives
Pennsylvania	Columbia Gas	250,000	28.9	11/96	Pending Legislation
	Equitable Gas	249,000	28.6	04/98	
	National Fuel Gas Dist. Co.	19,000	2.2	09/97	
	Peoples Natural Gas Co.	315,000	36.2	04/97	
Virginia	Columbia Gas of Virginia	26,000	2.5	12/97	
	Washington Gas	58,000	5.6	07/98	
West Virginia	Mountaineer Gas Co.	185,000	19.6	In-Service	
Wisconsin	Wisconsin Gas	2,500	0.3	11/96	PSC Report
Wyoming	KN Energy	10,000	0.9	06/96	PSC Study Completed
	Questar Gas	19,000	1.9	1999	
TOTAL		18,091,475	1743.2		

* In most cases, regulatory approval is needed for utilities to offer residential transportation services

Source: American Gas Association, "Providing New Services To Residential Natural Gas Customers: A Summary of Customer Choice Pilot Programs and Initiatives." Issue Brief 1998-03. 7/31/98 pps. 2,3.

GAS RESTRUCTURING ACTIVITIES BY STATE

The following materials were excerpted from the American Gas Association, "Providing New Services To Residential Natural Gas Customers: A Summary of Customer Choice Pilot Programs and Initiatives." Issue Brief 1998-03, 5/7/98

CALIFORNIA

On Jan. 21, 1998, the CPUC Natural Gas Division released a report, "Strategies for Natural Gas Reform: Exploring Options for Converging Energy Markets," with the goal of expanding natural gas customer choice. The following is excerpted from the study's executive summary:

> Notwithstanding the significant benefits brought by past reforms in natural gas, all customers do not have adequate choices. With opportunities for customer choice greatly enhanced by California's electric reforms, the Commission should now eliminate regulatory policies which artificially segregate and constrain customer choices in the natural gas industry. Policies should be sufficiently flexible to accommodate nascent competition in combined electric and gas products and services and allow for the possible further convergence of competitive retail utility markets and other markets.
>
> Understanding the need to revisit current natural gas policies and analyze their appropriateness in a continuously changing market, the Commission stated its intent to develop a Natural Gas Strategy in its 1997 Business Plan. The Commission directed the Division of Strategic Planning "to provide an analysis of the long-term regulatory outlook for the natural gas industry and how regulation can be redesigned to respond to that outlook." To comply with the Commission's mandate, the Division has reviewed the history, evaluated the current status, and considered future industry trends. In addition to discussions with Commissioners and staff, we also have drawn upon the input and expertise of numerous industry stakeholders, including utilities, gas marketers, brokers, aggregators, and representatives of small and large gas consumers in identifying trends and problem areas.
>
> **Guiding Principles**
>
> We recognized that caution must be exercised with any attempt to prescribe regulatory policies in anticipation of how future markets will develop. Thus, we have developed principles to guide us in formulating strategies to address current and foreseeable challenges. The following principles, similar to the Commission's past reform strategies in the telecommunicationsand electric industries, are intended to provide such guidance: 1) Replace traditional regulation with competitive forces in those markets where competition or the potential for significant competition exists, thereby allowing market forces to dictate lower prices; 2) Reform regulation for those utility functions that are not fully competitive; 3) Maintain a standard of consumer protection in both competitive and non-competitive markets; and 4) Maintain supply reliability and ensure the safety of consumers' natural gas services.
>
> To achieve these principles, the Division presents a four-prong strategy broadly defined as: 1) unbundling competitive and noncompetitive services; 2) streamlining regulation for noncompetitive services; 3) mitigating the potential for anti-competitive behavior; and 4) establishing appropriate consumer protections.

MASSACHUSETTS

On March 14, 1997, a joint motion was made to the Massachusetts Department of Public Utilities (Now Department of Telecommunications and Energy (DTE)) by the state's attorney general, the state's Division of Energy Resources, the Associated Industries of Massachusetts, and the Energy Consortium to issue a ruling expanding the scope of an earlier filed petition. The motion proposed that the Commission address the establishment of unbundled rates and services for all customer classes on a statewide basis and examine issues related to developing competition for, and restructuring of, the natural gas industry in the state. The motion suggested that such an effort would require addressing and resolving such issues as mandatory versus voluntary capacity release, provider of last resort service configuration, standard offer contracts and rates, mechanics of disposition of upstream and on-system capacity, access to constrained receipt points and such other major unbundling, restructuring, and competitive issues raised by the stakeholders. The motion envisioned competition and supplier choice starting as early as Jan. 1, 1998, and statewide no later than Sept. 1, 1998, for all customer classes.

The Commission has directed Massachusetts natural gas local distribution companies (gas utilities) to commence a collaborative process to develop common principles and procedures for unbundling gas utility natural gas services in Massachusetts. The ten Massachusetts gas utilities have formed a working group which is in the process of developing a structure and agenda for this industry-wide collaborative process. The first meeting of the full collaborative was Sep. 15, 1997, with the intent of developing a work process and schedule that will result in the filing of an industry-wide standard approach to unbundling gas utility services in Massachusetts for implementation by the 1998-1999 heating season. All interested stakeholders are encouraged to attend and participate in these collaborative discussions.

The Commission has articulated the following principles that are important to the success of a competitive natural gas market: 1) provide the broadest possible choice; 2) provide all customers with an opportunity to share in the benefits of increased competition; 3) ensure full and fair competition in the gas supply market; 4) functionally separate supply from local distribution services; 5) support and further the goals of environmental regulation; and 6) rely on incentive regulation where a fully competitive market cannot exist, or does not yet exist.

The Commission expects that the collaborative discussions will identify those issues for which generic jurisdictional, regional or pipeline system principles would be either necessary or useful in assuring the development of efficient unbundled retail natural gas services. Further, the Commission anticipated that, at a minimum, the participants will address the following issues:1) services that can be offered on a competitive basis; 2) terms and conditions of service; 3) consumer protections and social programs; 4) mitigation of gas-related and non-gas related transition costs;
5) third party supplier qualifications; and 6) curtailment principles that govern the use of natural gas under emergency conditions when gas supply is disrupted.

On Nov. 21, 1997, the Collaborative issued a status report summarizing the group's progress to date. The Collaborative identified several issues for study, and developed five working groups (capacity disposition, rate unbundling, consumer protection/low-income, supplier registration, and enrollment, billing, termination, & information exchange) to examine those issues. The groups have identified objectives and have set up a schedule that should allow implementation of customer choice in the state by Nov. 1, 1998.

Unable to reach final consensus, the collaborative requested that the Commission in March 1998 to determine the state's policy on capacity assignment. Marketers wanted voluntary assignment, while utilities wanted mandatory assignment. Each party provided its recommendation to the Commission.

Bay State Gas Company

Bay State Gas received approval from the DPU in July 1996 to launch the *Pioneer Valley Customer Choice* program, the first residential unbundling program in New England. This two-year residential program allowed up to 10,000 residential customers to begin purchasing gas supplies from an alternative supplier. Enrollment in the program began Aug. 1, 1996. Availability was awarded on a first-come, first-served basis to the company's 83,000 residential customers in 16 cities and towns in western Massachusetts. Service in the program began Nov. 1, 1996.

Bay State invited a broad spectrum of stakeholders to give input into the design of the pilot program. Representatives of the Commission's Gas and Consumer Divisions, the state's attorney general's office, the state's Division of Energy Resources, as well as national (UtiliCorp United and Enron Capital & Trade Resources) and regional marketing companies, other gas utilities, and electric utilities participated in the design of the program.

In designing the program, Bay State sought to: 1) Provide residential customers with an opportunity to make an informed but not overly burdensome choice from among competing suppliers; 2) Provide an opportunity to develop systems and procedures to support residential transportation services; 3) Provide participants with the opportunity to learn what customers want and how to deliver services to the residential market; and 4) Provide regulators with the information they need to allow choice to be provided to all customers.

Bay State has undertaken a large communication effort to provide information to customers, suppliers, community leaders, the media, trade allies, the financial community, and the company's employees. Using a variety of communication methods (direct mailings, mass communications, Internet), Bay State's communication plan pursued the following objectives: 1) To educate customers about the impact of changing regulation and customer choice; 2) To create an awareness of the pilot program and its impact; 3) To build customer interest in participating in the program; 4) To communicate the process by which customers can participate (or avoid direct marketing); and 5) To solicit customer feedback to modify the communications plan as needed.

As part of its initial customer education effort, Bay State made natural gas usage and total expenditure data for a recent 12-month period available to customers, upon request, as well as credit and payment history information. Bay State also provided customers with a breakdown of gas supply and distribution costs in order to help them in their decision-making process. Customers could then provide suppliers with this information during the enrollment season. After the enrollment period closed, each marketer received historical usage information for their pool members.

Bay State offered suppliers a *pro rata* assignment of firm capacity on all of its upstream pipelines (excluding the capacity used to deliver Canadian gas by displacement through the Portland Pipe Line) with an option to take capacity only on Tennessee Gas Pipeline for delivery at the Pioneer Valley city-gates.

Assignment of pipeline capacity was voluntary and suppliers could elect to deliver gas through any of their other resources. If capacity is taken, suppliers will receive approximately 38 percent of their peak day pool requirements, priced at the weighted average demand cost of Bay State's upstream pipeline entitlements. Pioneer Valley is located on the Tennessee Gas Pipeline system.

Storage capacity is not assigned during the first year of the pilot but Bay State will make available a supplemental supply service for any volumes above a supplier's Maximum Daily Delivery Obligation. Under deliveries are cashed out on a daily basis based on the pipeline or supplemental supply service as the marginal supply source. Under-deliveries during OFO periods will be assessed at $50/MMBtu.

Customers will receive one bill from their supplier for both their gas supply charges and Bay State's transportation service unless the supplier elects to have Bay State bill separately for the transportation service. Under the first option, Bay State will bill the supplier for transportation services provided to their pool, and will provide suppliers with cycle meter read consumption data by customer to assist them in billing. Each marketer pays a one-time administrative fee of $10/customer and marketers must satisfy creditworthiness standards and agree to abide by a code of conduct and consumer protection policies. Bay State maintains a list of qualified marketers that it will provide to customers upon request.

Bay State does not require suppliers to have an agreement or contract with customers and unless the provisions of an agreement require a customer to commit for a certain period of time, customers are free to switch suppliers or return to Bay State sales service. The customer confirmation process occurs on a daily basis over Bay State's website. An account number, meter number, and street number is needed for a confirmation.

The initial size of the pilot was limited by the ability of Bay State to develop and implement new administrative systems to support a program where customers can choose from many alternate suppliers. Bay State estimated it would incur approximately $400,000 of incremental administrative costs to implement the pilot. Approximately one-quarter of these costs would be recovered from suppliers through the administrative fee.

Thirty-six marketers initially expressed interest in participating and nine of 10 participating marketers qualified for the program by receiving more than 100 customers. Qualified marketers included AllEnergy Marketing, Broad Street/Energy One, Total/Louis Dreyfus, Green Mountain Energy, KBC Energy, National Fuel Resources, NorAm Energy, WEPCO Gas, and Western Gas Resources. Marketers had to enroll a minimum of 100 heating and/or non-heating customers by Oct. 1, 1996. The top four marketers -- NorAm Energy, Broad Street/Energy One, Green Mountain Energy, and KBC Energy -- enrolled about 75 percent of total pilot customers.

Bay State officials said the results of the open season have exceeded their expectations. Marketers offered residential customers savings from $50 - $100 per year. On average, customers saved $67 per year relative to Bay State's rates. Offers ranged from flat per-unit discounts to guaranteed price savings. Marketers also included signing bonuses and bonus credits in signing up customers. According to Bay State, the average residential customer in the Pioneer Valley (Springfield and Northampton service areas) consumes approximately 112 Mcf/year, meaning the aggregate annual volume for the pilot was more than 1.1 Bcf. In addition, marketers signed up about 30 households interested in converting to gas service from alternative fuels.

As of Oct. 21, 1996, about 6,500 residential customers had enrolled in the pilot. Bay State reported that customers participating in that pilot saved between 5% and 18% on their annual gas bills. The program is part of Bay State's overall restructuring into three distinct business units - local transportation, energy products and services and energy ventures.

After evaluating the pilot's initial success in attracting almost 6,500 Springfield-area participants, in July 1997 the Commission approved Bay State's request to expand its pilot program. The second phase of the program, which lasts up to one year, extended eligibility to all of Bay State's residential and small business customers in its Western Massachusetts service area. In addition, small business customers in the Southeastern Massachusetts service area were eligible for the first time to participate in the program. Enrollment for the expanded program began Aug. 1, 1997, and remains open for the duration of the program.

Choice Advantage from Bay State Gas provides competition and choice in Western Massachusetts to all 83,000 residential and all 6,000 small business customers (i.e., businesses using less than 5,000 therms per year), as well as to all 10,000 small business customers in the company's Southeastern Massachusetts service area. Customers participating in the pilot program have the opportunity to purchase natural gas directly from their supplier of choice, including Bay State Gas, while continuing to rely on the utility for service and for delivering the gas to their home or business.

In addition to expanded eligibility, the second year of the pilot includes important new features: 1) Customers are allowed to enroll throughout the program -- the previous the enrollment "window" was only 60 days; 2) Customers are allowed to change gas suppliers during the year; 3) Bay State has made gas storage capacity available to marketers on a voluntary basis and enhanced supplemental supply services to participating marketers; and 4) Bay State and retail energy marketers will be conducting joint marketing programs to learn more about how to work together to better serve customers and attract new customers.

In October 1997, Bay State filed a rate case with the Commission. In the filing, Bay State asked for recovery of $1.6 million for external expenses related to unbundling. The company also requested that a two-year rate "bridge" be implemented, with an incentive mechanism which would allow ratepayer/stockholder sharing of earnings above the allowed rate of return. The Commission approved Bay State's plan in December 1997.

NEW YORK

On March 28, 1996, the New York Public Service Commission (PSC) approved nine utilities' compliance filings that serve to increase competition in gas markets throughout the state. The new regulations will allow all customers in New York to purchase gas supplies from their supplier of choice. Residential and commercial customers will be able to aggregate their loads to increase purchasing power.

Under the new regulations, any customer that consumes 3,500 Dth/year or is part of an aggregated group that consumes 5,000 Dth/year will be eligible to choose their own natural gas supplier. About 35 homes with gas heat use approximately 5,000 Dth/year. Utilities will provide itemized billing that will allow customers to identify the costs of the commodity as well as other portions of their gas service. The following section describes the rulings of the Public Service Commission on March 28, 1996, as well as the rehearing order effective Sept. 13, 1996 and subsequent rulings.

Pipeline and Storage Capacity

The PSC will allow gas utilities to require that customers converting to transportation take associated pipeline capacity for a three-year period or until the pipeline contract expires, whichever comes first. The amount of capacity released will be no less than the customer's historical average daily usage during the peak month, normalized for weather. Released capacity should be priced at the gas utility's weighted average capacity cost. Capacity released to a marketer will "stay" with the customer if the customer desires to switch to a new marketer or return to sales service, however, the marketer will be able to rerelease the capacity if it is not needed to meet its service obligations.

The PSC ordered its staff to further explore the unbundling of storage services and the problems that may exist due to pipeline storage facilities being certificated under Natural Gas Act Section 7(c), which was deemed not releasable by FERC Order 636A. The PSC solicited comments on storage issues in the first half of 1997. Most of the comments agreed that there should not be mandatory assignment of storage and pipeline capacity associated with storage. As of August 1997, two utilities (National Fuel and Niagara Mohawk) has direct assignment of storage, while most of the others have "virtual" storage release (utility retains title).

Aggregation

The PSC's initial ruling supported the aggregation of small volume consumers into one group to allow them to enjoy some of the benefits of competition in the industry. The March 28, 1996, order requires each utility to file a formal aggregation program (if it had not done so already) and a supplier service tariff. Limitations may be placed on those programs that have 5 percent of core customers converting from sales to transportation in the first year, 10 percent in the second year and 15 percent in the third year, if the gas utility thinks a mass migration of customers to transportation service would be difficult to administer and increase the costs to remaining core customers. Gas utilities may also limit the percentage of any service class from switching to transportation to 25 percent of the current sales customers in each of the first three years. Fees for creating and administering the aggregation programs will not be permitted; however, gas utilities are free to propose them in the context of individual rate cases.

Consumer Protection

Marketers seeking to obtain transportation services from gas utilities to sell gas to residential customers will be required to meet the following set of performance requirements:

•Contracts between the marketers and the customers must contain specific language advising the customers of any protection they have waived. Each marketer must file with the staff of the PSC's Consumer Services Division a copy of its standard contract;

•Marketers must have a system in place to handle customer complaints and the PSC help and hotline numbers must be provided to customers;

•Bills are to be clear and in "plain" language and the staff of the Consumer Services Division must receive a sample bill; and

•Procedures are to be in place to ensure residential customers receive adequate notice of the termination of gas supply services. Notification must be sent at least 15 days before service is discontinued.

In addition to the above protection, gas utilities will still have the obligation to serve residential customers if a marketer does not deliver the appropriate supply volume. The PSC also directed its staff to facilitate meetings to develop new curtailment and interruption procedures taking into account the changes in the marketplace. The PSC has requested comments on short-term curtailment procedures and compensation from the state's utilities and has asked for specific procedures for long-term curtailments.

Creditworthiness

In order to standardize some of the basic aspects of creditworthiness, the PSC directed each gas utility to incorporate several concepts into their tariff filings:

•The results of creditworthiness checks performed prior to allowing marketers to provide service should be communicated to the applicant within two weeks receipt of the application. Utilities are to respond to any grievance of a marketer denied service within 10 days and a statement to that effect must appear on the application for transportation service;

•Security deposits should be refunded to the marketer when it meets the level of credit criteria that no longer requires a security deposit; and

•All security deposits held by gas utilities should accrue interest at the PSC's Other

In addition, marketers dissatisfied with the gas utilities' resolution of this issue are directed to petition the Director of the Office of Accounting and Finance for relief.

Administrative Matters

The PSC also ruled on several administrative matters. Customers returning to core or sales service will be treated no differently than new applicants for service, nor will they be charged a fee for returning to sales service. In addition, the PSC encouraged parties to readdress the issue of "human needs" customers. These customers currently are required to have full backup service in addition to their transportation service.

Rate Issues

For most of the state's utilities, New York's open access program began on May 1, 1996. Early reports have not shown a great amount of interest in aggregating residential customers in New York. Marketers initially appear to be concentrating their efforts on small commercial and industrial customers where the margins are greater.

Due to the significant price volatility in gas prices during the 1996-1997 winter, the PSC ordered the ten largest gas utilities to offer a fixed price option under its regulated service if they did already have such a program. Some utilities offered to hedge gas based on customer response. Others hedged based on a set portion of its winter gas supply. Another utility stated that utilities did not need to offer this service since marketers already have fixed price options. Marketers themselves are against regulated utilities offering fixed price services, calling it anticompetitive. State officials noted that the regulated fixed price option should only be temporary until enough marketers are offering this service. On Oct. 7, 1997, the PSC rejected most of these objections and issued the minimum elements for the fixed price plans, which must be in place by Dec. 1, 1997.

OHIO

The Ohio General Assembly passed natural gas alternative regulation legislation, which was signed into law in June 1996. The law establishes customer choice as a state policy in the supply of natural gas services, and allows local gas utilities to unbundle their gas supply function and compete against other suppliers upon a Commission finding that competitive circumstances exist on the system. The Public Utilities Commission of Ohio (PUC) has proposed a set of rules to implement the law, including a code of conduct regarding utility actions relating to competing with marketers.

Cincinnati Gas & Electric

CG&E received approval for enhancements to its existing non-residential firm transportation service program, and in addition, received approval for a residential aggregation/transportation program that would allow customers, effective Dec. 1, 1997, to pick an alternative gas supplier while CG&E continues to provide local delivery service. As of April 1998, CG&E had approximately 9,500 residential customers enrolled in its choice program.

CG&E's program is now available to all customers in its entire service territory. However, participation by customers in the program is voluntary. CG&E will continue to purchase natural gas for any customers who do not wish to choose another supplier. Customers' bills for local delivery service will continue to come from CG&E. The cost of gas purchased from the supplier will also be billed by CG&E, or can be billed separately by the supplier, at the supplier's discretion. CG&E continues to provide its customers with additional information on its customer choice program, including a list of suppliers who have met CG&E's eligibility requirements. To enroll in the program, customers will select a supplier and sign a contract with the supplier and a consent form.

All Ohio gas customers whose payments are current with CG&E may participate in the program. Customers may choose any qualified supplier or may stay with CG&E. Customers who are enrolled in the program will be notified by CG&E when their supplier service will begin. The first bill showing gas from a supplier was received by the customer on their normal billing date following their notification of CG&E of their desire to switch.

For all customers, CG&E will continue to provide all gas distribution services, including: 1) gas system repair and maintenance; 2) emergency response to gas odors and leaks; and 3) energy conservation and safety information.

Columbia Gas of Ohio

Columbia Gas of Ohio (COH) filed its Customer CHOICE program at the PUC in October 1996 and received approval in January 1997. The program was initially offered for the greater Toledo area, where approximately 170,000 customers were eligible. Those eligible were residential and commercial customers using less than two million cubic feet per year. After one year of the program's existence, COH filed to the PUC, on March 31, 1998, for expansion throughout the remainder of the service territory.

Columbia offers several billing options for the Customer CHOICE program. Marketers may bill the customer for the gas cost and have Columbia bill the customer for the transportation cost, marketers may opt for Columbia to bill the customer for the entire amount, or, for commercial customers only, marketers may bill for the entire amount through an automatic debit account to Columbia.

The program is open to all marketers, but marketers must agree to participate in Columbia's aggregation service, as defined in its tariff. Marketers are required to meet certain creditworthiness standards, agree to operate under defined standards of conduct and a code of ethics, and must have a minimum of either 200 residential customers or a group of commercial customers with at least 20,000 Mcf of annual throughput to participate in the program.

The program is voluntary and Columbia will continue to provide sales service to those customers who elect not to choose another supplier. During the first year of the program, any stranded costs that resulted from marketers contracting for their own capacity or imbalances in the recovering excise taxes were recovered through a rider on all customers. This rider will not be in effect for the state-wide rollout.

In January 1998, the PUC approved Columbia's stranded cost settlement. This agreement allows Columbia a chance to recover its stranded costs over a four year period through voluntary capacity assignment revenues, daily balancing fees, interstate pipeline refunds, and part of Columbia's off-system revenue. Columbia will be responsible for the stranded costs not covered by these measures, roughly eleven percent of all those costs, and cannot raise its base rates before 2000. The parties involved with this agreement were Columbia, the PUC, Ohio's Consumer's Counsel, marketers, affected cities, and consumer groups.

By April 1, 1998, 50,506 residential and 5,343 commercial customers signed up for the program, with marketers offering a wile variety cf pricing. customers have signed up for fixed prices, percentage discounts, rebates from marketers, and variable prices. Estimated savings through the winter of 1998 are reported to be approximately $6.5 million.

Dayton Power & Light

Dayton Power & Light (DP&L) filed a pilot program with the PUC in March 1998 which would allow up to 25,000 small commercial and residential customers to choose their gas supplier. The pilot, scheduled to begin Nov. 1, 1998, would be open to all customers in Miami County that consume less than 50 Mcf per month. Customers could receive one bill from DP&L or could have the supplier bill separately.

East Ohio Gas

On July 2, 1997, the Public Utilities Commission of Ohio ("PUCO") approved an application by the East Ohio Gas Company ("East Ohio") to implement the initial phase of its Energy Choice program which provided opportunities to approximately 173,000 residential, commercial and industrial customers in ten counties to select their own provider of natural gas. The initial phase of the program began with gas flowing November 1, 1997, and will last for 18 months. If the program operates successfully over the first 12 months, East Ohio may expand the initial phase after its first year of operation. Assuming successful program operation, East Ohio expects to make the Energy Choice program available to all of its 1.2 million customers within the first year following the 18-month initial phase.

Participation in the program has surpassed expectations. As of March, 1998, a total of 33,465 residential customers and 2,329 non-residential customers have selected suppliers under this program. In all, twelve marketers are actively providing gas service to customers under the program. Another six marketers have been approved to participate, but are not actively doing so at this time. All but one of the twelve marketers are serving both residential and non-residential customers. One marketer is serving non-residential customers only.

Comprehensive Electricity Restructuring Bills

I. Comprehensive Electricity Competition Act (introduced by Department of Energy Secretary Frederico Pena)

A. Mandate for Competition
1. Retail choice required by 2003
2. State regulatory authorities permitted to opt out of competition if consumers are better served under existing regulation

B. State Authority

1. States would continue to determine retail stranded cost recovery
2. States may impose conditions, such as fees, on receipt of electricity by ultimate customers
3. States may impose reciprocity requirements

C. FERC Authority

1. FERC can require utilities to turn over operation of transmission facilities to an Independent System Operator
2. FERC has jurisdiction over rates, terms and conditions of unbundled retail electricity transmission.
3. FERC can require public utilities to provide open access transmission
4. FERC has jurisdiction over transmission services of municipals, cooperatives, TVA and federal PMAs.
5. FERC can approve regional transmission planning agencies
6. FERC can allow for recovery of retail stranded costs if a state commission does not have authority
7. FERC authorized to remedy market power in the wholesale sector
8. FERC allowed to remedy market power in the retail sector upon request of a state, and could order divestiture
9. FERC granted jurisdiction over merger or consolidation of electric holding companies and generation-only companies

D. PUHCA/PURPA Reform

1. Section 210 of PURPA repealed
2. Repeals PUHCA and replaces with PUHCA 1998 (FERC and states given greater access to holding company books and records)

b. EIA will collect & publish information on impacts of wholesale and retail competition

II. Bumpers Bill ("Electric Consumers Protection Act of 1997"--S. 237)
Introduced by Sen. Dale Bumpers (D--AR) in January 1997

A. Mandate for Competition
1. Retail choice required by December 15, 2003
2. Any action taken by a state to promote competition would be grandfathered
3. Sellers of electric service will have reasonable and nondiscriminatory access to unbundled local distribution and retail transmission facilities
4. Customers may aggregate to purchase service as a group

B. State Authority
1. States are responsible for calculating stranded cost for any previously regulated utility that submits an application for recovery
   a. FERC will calculate stranded cost if a state does not do so
   b. nonregulated utilities (munis, co-ops) may calculate their recovery by one of two methods specified by bill
2. States may continue to regulate local transmission and distribution
3. States may impose requirements on any entity seeking to provide service, as long as the requirements are nondiscriminatory
4. States may assess a universal service charge

C. FERC Authority
1. If Congress does not create regional boards to calculate stranded costs for multistate holding companies, recovery falls into FERC jurisdiction
2. FERC will establish transmission regions and designate an ISO for each one
3. FERC will have jurisdiction over mergers that affect retail and wholesale markets

D. PUHCA/PURPA Reform
1. PUHCA would be repealed one year after enactment, but would be replaced with provisions that transfer authority from the SEC to FERC
   a. FERC may exempt holding companies from provisions if each affected state consents
   b. new provisions will not apply if FERC certifies that retail competition exists
2. No public utility is required to enter into PURPA contracts after enactment, or whenever retail competition is implemented in all of its service territories

E. Federal and State Access to Books and Records
1. FERC and states have access to records of holding companies and affiliates deemed relevant with respect to rates, but information is protected

F. Other Provisions
   1. Renewables
      a. each generator's supply must include 5% renewables (including hydro) by 2003, 9% by 2008 and 12% by 2013
      b. FERC will establish National Renewable Energy Trading Program
   2. Retail and wholesale suppliers are granted right to sell to customers of TVA
   3. EPA must report to Congress the impact of competition on air pollution standards

III. Schaefer Bill ("Electric Consumers' Power to Choose Act of 1997"--H.R. 655) Introduced by Rep. Dan Schaefer (R-CO) in February 1997

A. Mandate for Competition
   1. Retail choice required by December 15, 2000

B. State Authority
   1. States must decide within six months of enactment of bill whether to institute their own retail choice program
      a. nonregulated utilities must also decide within six months whether to establish retail choice
   2. States may assess charges for funding:
      a. stranded cost recovery
      b. universal service
      c. environmental programs
   3. States will put into effect flexible pricing procedures and incentive-based rate regulation

C. FERC Authority
   1. FERC decides which distribution facilities are subject to state jurisdiction
   2. Any state law regarding retail choice enacted after 2000 is preempted by FERC authority
   3. FERC can order a utility to provide transmission service

D. PUHCA/PURPA Reform
   1. PUHCA "ceases to apply" when customers in all states of a holding company's territory have customer choice
   2. PUHCA would be repealed if each state determines that retail customers have nondiscriminatory choice
   3. PURPA is amended to relieve utilities of Section 210 requirements if their customers can purchase service elsewhere on a nondiscriminatory basis

E. Federal and State Access to Books and Records
   1. FERC and states would have access to records of holding companies and affiliates

if records are relevant with respect to jurisdictional rates

F. Other Provisions
1. Renewables
a. each generator's portfolio must include at least 2% renewables by 2000, increasing to 4% by 2010
b. FERC will establish a Renewable Energy Credits trading system to help generators meet requirements

IV. DeLay Bill ("Consumers Electric Power Act of 1997"--H.R. 1230) Introduced by Rep. Tom DeLay (R-TX) in April 1997

A. Mandate for Competition
1. Retail choice becomes effective January 1, 1999
2. Requires utilities to functionally unbundle T&D from generation
3. All customers may purchase service from any provider

B. State Authority
1. States may not impose exit fees or subsidies for stranded cost recovery
2. States may not regulate prices, terms or conditions of service
3. States may assess local distribution access charges to ensure that service is provided to residential customers that cannot afford it
4. States may establish requirements to preserve universal service, maintain reliability, protect consumer rights
5. States must establish a nondiscriminatory certification process for providers
6. States must assign a service provider for any customer that does not choose one

C. FERC Authority
1. FERC will set rates after 1/1/99 if a state has not enacted competitive pricing
2. FERC has authority to provide for nondiscriminatory prices, terms and conditions of transmission and distribution
3. FERC must issue rules by 9/30/99 that provide for nondiscriminatory T&D access
4. FERC will defer to states regarding distribution systems where state authority is granted (Sec. 4--universal service, conservation, renewables, R&D)
5. FERC must determine by 9/30/99 utilities' market power, and may mitigate by:
a. restricting sales outside franchise area
b. ordering divestiture of assets that are source of market power

D. PUHCA/PURPA Reform
1. Utility is exempt from PUHCA once a state determines competition exists, pending notification to FERC and the SEC
2. Section 210 of PURPA will no longer apply if competition exists, but existing

contracts will not be affected

E. Other Provisions
   1. Thirty months after enactment, FERC must submit to Congress a report summarizing rate reductions, progress of competition and reliability of service
   2. Part II of the FPA will no longer be in effect after enactment of this bill

V. Thomas Bill ("Electric Utility Restructuring Empowerment and Competitiveness Act of 1997"– S. 722) Introduced by Sen. Craig Thomas (R-WY) in May 1997

A. Mandate for Competition
   1. Does not impose federal mandate to require retail choice

B. State Authority
   1. States may order retail competition if it benefits consumers
   2. States retain jurisdiction over retail sales, and receive jurisdiction over sales to federal facilities
   3. States may establish and enforce performance and reliability standards for sales, marketing and delivery
   4. States may assess charges for funding:
      a. stranded cost recovery
      b. universal service
      c. low-income assistance programs
      d. environmental/renewable energy programs

C. FERC Authority
   1. Removes wholesale sales from federal regulatory purview
   2. FERC is granted jurisdiction over wholesale transmission services
   2. FERC must promulgate final rule exempting specified holding companies (those that hold only QFs, EWGs or FUCOs) from books and records access
   3. SEC authority under PUHCA is transferred to FERC

D. PUHCA/PURPA Reform
   1. PUHCA is repealed
   2. Section 210 of PURPA is repealed
   3. Existing PURPA contracts are to be honored
   4. After date of enactment, no electric utility will be required to enter into new contracts to purchase or sell energy under Section 210

E. Federal and State Access to Books and Records
   1. Each holding company and associate company must make available to FERC

books and records deemed relevant to the costs incurred for transmission or energy sales in interstate commerce
2. Affiliates of holding companies must make available to FERC books and records deemed relevant to costs incurred for any transaction with another affiliate
3. Any company in a holding company system or its affiliates must make available to FERC books and records deemed relevant to costs incurred by such a company
4. Any holding company or its associate or affiliate must produce for state commissions books and records that have been identified in a proceeding before that commission as relevant for the discharge of state commission responsibilities

F. Other Provisions
1. Inspector General of the Treasury must submit to Congress a report regarding the impact of specified utility tax provisions on electric competition
2. Amends the FPA to repeal conflict of jurisdiction guidelines

VI. Markey Bill ("Electric Power Competition and Consumer Choice Act of 1997"–H.R. 1960)
Introduced by Rep. Edward Markey (D-MA) in June 1997

A. Mandate for Competition
1. No federal mandate for retail competition is established
2. Utilities are prevented from providing service in states open to competition if there is no competition in utilities' service territory.

B. State Authority
1. States must initiate a retail competition rulemaking proceeding
2. States have authority to "opt out" of competition if it is not in state's public interest
3. States have increased power in approving mergers and acquisitions and mitigating market power

C. FERC Authority
1. FERC's approval process for mergers and acquisitions expanded and defined
   a. company seeking acquisition must prove:
      1. no acquisition premium will be recovered in regulated rates
      2. each state involved has certified no adverse effects on retail rates will occur
   b. FERC may then approve merger if it finds:
      1. merger will not adversely affect competition
      2. merger will result in substantial cost reductions
      3. merger will be entered into on arm's-length basis
   c. FERC has authority to establish terms and conditions that maintain provisions

necessary for merger approval

2. FERC has increased authority to curb excessive market power, review affiliate transactions and guard against anticompetitive practices
3. FERC will establish regional transmission markets designed to:
   a. ensure development of competitive electricity markets
   b. ensure recovery of prudent transmission costs
   c. prevent "pancaking" of transmission rates
   d. prevent nondiscriminatory access to T&D facilities
4. FERC will oversee a newly-created Electric Reliability Council

D. PUHCA/PURPA Reform
1. Utilities may be free from PUHCA and Section 210 of PURPA if a state opens its market to competition
2. PURPA is amended to encourage renewable generation technologies

E. Federal and State Access to Books and Records
1. FERC and states have access to books and records of holding companies and affiliates that are relevant with respect to their jurisdictional duties

F. Other Provisions
1. Renewables
   a. generators must submit to DOE renewable energy credits equal to 10% of sales by 2010
   b. DOE establishes Renewable Energy Credit trading system
2. Universal service
   a. federal-state board is created to review universal service requirements in restructured electricity industry
3. Federal Trade Commission (FTC) is granted authority to issue rules assuring fair disclosure of information
4. President or designee is given authority to issue rules preventing utilities from gaining competitive advantage by owning "dirtier" power plants not subject to pollution standards as new generation sources

<u>**PUHCA/PURPA Reform Bills**</u>

I. D'Amato Bill ("Public Utility Holding Company Act of 1997"–S. 621)
Introduced by Sen. Alfonse D'Amato (R-NY) in April 1997

A. Repeal of PUHCA
1. PUHCA is repealed effective 18 months after enactment of bill
2. SEC authority under PUHCA is transferred to FERC

B. State and FERC Authority
   1. States and FERC retain jurisdiction to determine whether a public utility may recover in rates any costs of affiliate transactions
   2. FERC must issue rules to exempt specified holding companies (those that hold only QFs, EWGs or FUCOs) from providing access to books and records
   3. FERC must issue rules exempting any person or transaction from providing access to books and records if regulation of such persons or transactions is irrelevant to jurisdictional rates of a public utility

C. Federal and State Access to Books and Records
   1. Each holding company and associate company must make available to FERC books and records deemed relevant to the costs incurred for transmission or energy sales in interstate commerce
   2. Affiliates of holding companies must make available to FERC books and records deemed relevant to costs incurred for any transaction with another affiliate
   3. Any company in a holding company system or its affiliates must make available to FERC books and records deemed relevant to costs incurred by such a company
   4. Any holding company or its associate or affiliate must produce for state commissions books and records that have been identified in a proceeding before that commission as relevant for the discharge of state commission responsibilities

II. DeFazio Bill (H.R. 1359)
Introduced by Rep. Peter DeFazio in April 1997

A. PURPA Reform
   1. Amends PURPA to establish a National Electric System Public Benefits Fund to provide grants for support of public programs
      a. requires generators to contribute funds in each year equal to one-half the aggregate cost of implementing certain public programs
      b. authorizes states to establish programs and apply for matching funds
   2. Creates National Electric System Public Benefits Fund Board to oversee Fund